



Control Number: 51415



Item Number: 299

Addendum StartPage: 0

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SOAH DOCKET NO. 473-21-05382021 MAR 31 PM 2:07
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APPLICATION OF SOUTHWESTERN	§	BEFORE THE STATE OFFICE
ELECTRIC POWER COMPANY FOR	§	OF
AUTHORITY TO CHANGE RATES	§	ADMINISTRATIVE HEARINGS

DIRECT TESTIMONY AND EXHIBITS

OF

MARK E. GARRETT

ON BEHALF OF

CITIES ADVOCATING REASONABLE DEREGULATION

March 31, 2021

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EXHIBITS

Exhibit MG-1:	Qualifications
Exhibit MG-2:	Schedules
Exhibit MG-3	Summary of Garrett Group LLC’s Incentive Compensation Survey of the 24 Western States
Exhibit MG-4	RFI responses referenced in testimony

WORKPAPERS

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I. WITNESS IDENTIFICATION

Q: PLEASE STATE YOUR NAME AND OCCUPATION.

A: My name is Mark Garrett. I am the President of Garrett Group Consulting, Inc., a firm specializing in public utility regulation, litigation, and consulting services. My business address is 4028 Oakdale Farm Circle, Edmond, 73013.

Q: PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND YOUR PROFESSIONAL EXPERIENCE RELATED TO UTILITY REGULATION.

A: I received my bachelor's degree from the University of Oklahoma and completed postgraduate hours at Stephen F. Austin State University and the University of Texas at Arlington and Pan American. I received my juris doctorate degree from Oklahoma City University Law School and was admitted to the Oklahoma Bar in 1997. I am a Certified Public Accountant licensed in the States of Texas and Oklahoma with a background in public accounting, private industry, and utility regulation. In public accounting, as a staff auditor for a firm in Dallas, I primarily audited financial institutions in the State of Texas. In private industry, as controller for a mid-sized corporation in Dallas, I managed the Company's accounting function, including general ledger, accounts payable, financial reporting, audits, tax returns, budgets, projections, and supervision of accounting personnel. In utility regulation, I served as an auditor in the Public Utility Division of the Oklahoma Corporation Commission from 1991 to 1995. In that position, I managed the audits of major gas and electric utility companies in Oklahoma.

Since my departure from the Oklahoma Corporation Commission, I have worked as an independent consultant on numerous rate cases and other regulatory proceedings on behalf of various consumers, consumer groups, public utility commission staffs and

1 offices of attorneys general. I have provided testimony before the public utility
2 commissions in the states of Alaska, Arizona, Arkansas, Colorado, Florida, Indiana,
3 Massachusetts, Nevada, Oklahoma, Pennsylvania, Texas, Utah, and Washington. My
4 clients include industrial customers and groups of customers, hospitals and hospital
5 groups, universities, municipalities, and large commercial customers. I have also testified
6 on behalf of the commission staff in Utah and the offices of attorneys general in
7 Oklahoma, Indiana, Washington, Nevada, Pennsylvania and Florida. I have also served
8 as a presenter at the NARUC subcommittee on Accounting and Finance on the issue of
9 incentive compensation, and as a regular instructor at the New Mexico State University's
10 Center for Public Utilities course on basic utility regulation.

11 **Q: HAVE YOUR QUALIFICATIONS BEEN ACCEPTED BY THIS COMMISSION**
12 **IN OTHER PROCEEDINGS DEALING WITH COST-OF-SERVICE AND**
13 **OTHER RATEMAKING ISSUES?**

14 A: Yes, they have. A more complete description of my qualifications and a list of the
15 proceedings in which I have been involved are included at the end of my testimony.

16 **II. PURPOSE OF TESTIMONY AND SUMMARY OF**
17 **RECOMMENDATIONS**

18 **Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?**

19 A: The purpose of my testimony is to address, on behalf of the Cities Advocating Reasonable
20 Deregulation ("CARD"), various revenue requirement issues identified in the Company's
21 rate case application and to provide the Commission with recommendations for the
22 resolution of these issues. My testimony and recommendations address the issues of
23 Incentive Compensation, Other Post-Employment Benefits, Payroll expense, Self-
24 Insurance expense and Vegetation Management expense. I also address the accounting
25 treatment recommended by the Company for the proposed early retirement of the Dolet
26 Hills generation plant. I sponsor *Exhibit MG-2* in which the impacts of these
27 recommended adjustments are set forth. A summary of the impact of these adjustments
28 is shown in the table below.

Table 1: SOUTHWESTERN ELECTRIC POWER COMPANY Cities Advocating Reasonable Deregulation Summary of Recommendations Docket No. 51415; Test Year End March 31, 2020		
Description	Reference	Rate Impact
SWEPCO Payroll	Exhibit MG-2.1	\$ (623,862)
AEPSC Payroll	Exhibit MG-2.2	(1,489,989)
SWEPCO STI	Exhibit MG-2.3	(911,967)
AEPSC STI	Exhibit MG-2.4	(391,044)
LTI	Exhibit MG-2.5	(371,024)
OPEB SFAS 106 Expense	Exhibit MG-2.6	(2,117,108)
Vegetation Management	Exhibit MG-2.7	(5,000,000)
Self Insurance Expense	Exhibit MG-2.8	(1,689,700)
Dolet Hills Depreciation Expense	Exhibit MG-2.9	(705,313)
Amortization of Unprotected EDFIT	Exhibit MG-2.10	(7,602,161)
Depreciation Rate Adjustment	Exhibit MG-2.11	(6,940,283)
Total Operating Income Adjustments		<u>\$ (27,842,451)</u>

III. DOLET HILLS / EDFIT ADJUSTMENTS

1 **Q: WHAT IS THE RELATIONSHIP BETWEEN THE EXCESS DEFERRED**
2 **FEDERAL INCOME TAXES (“EDFIT”) AND SWEPCO’S PROPOSED**
3 **TREATMENT OF THE EARLY RETIREMENT OF THE DOLET HILLS**
4 **FACILITY?**

5 **A:** The generating plant at Dolet Hills is expected to be retired by December 31, 2021. The
6 Company is proposing to recover the substantial remaining undepreciated balance of the
7 plant through a combination of accelerated depreciation and utilization of the EDFIT
8 balances. In other words, the Company is proposing to transfer the ratepayers’ available
9 EDFIT balances to be used for shareholders’ benefit to recover the stranded cost of the
10 retired plant. Since the available EDFIT balances are not sufficient to completely cover
11 the remaining plant balances, the Company also proposes to accelerate depreciation
12 recoveries over a 4-year period to make up the difference.

13 **Q: PLEASE DISCUSS HOW THE COMPANY’S EXCESS DEFERRED FEDERAL**
14 **INCOME TAX (“EDFIT”) BALANCES ACCUMULATED AS RESULT OF THE**
15 **TAX CUTS AND JOBS ACT OF 2017 (“TCJA”).**

16 **A:** The TCJA was approved in December of 2017. It reduced the corporate Federal income
17 tax rate from 35% to 21% effective January 1, 2018, a 40% reduction in the tax rate. For

1 utilities, the TCJA created large EDFIT balances which represent federal income taxes
2 collected from ratepayers at the higher tax rate (35%) that the utility would no longer be
3 required to remit to the government because the tax rate was lowered to 21%. The TCJA
4 provides that the EDFIT balances must be classified as protected or unprotected. The
5 protected EDFIT balances relate to plant in service assets with different depreciation rates
6 for financial reporting and income tax purposes. In contrast, unprotected EDFIT balances
7 are timing differences not related to plant. The TCJA provides that the protected EDFIT
8 cannot be refunded to ratepayers any faster than under the Average Rate Assumption
9 Method (“ARAM”), which corresponds to the turnaround of the plant-related book/tax
10 timing differences. There are no restrictions on the timing of refunds of the unprotected
11 EDFIT balances to ratepayers.

12 To date, three years and three months of the accumulated protected EDFIT have been
13 amortized under the ARAM and SWEPCO has included those with the unprotected
14 EDFIT as a regulatory liability. In Docket No. 46449, the Commission directed
15 SWEPCO to address the impact of the tax rate reduction in its next rate case, which is the
16 current case. SWEPCO has proposed to use the unprotected EDFIT and the protected
17 EDFIT amortized through March 31, 2021 to offset the net book value of Dolet Hills,
18 which is expected to be closed by the end of 2021. However, because the amount of
19 available EDFIT will not completely offset the plant’s undepreciated balance, SWEPCO
20 proposes to depreciate the remaining unrecovered balance of Dolet Hills over the next
21 four years.¹

22 **Q: WHAT IS THE VALUE OF THE AVAILABLE EDFIT THAT SWEPCO**
23 **PROPOSES TO USE TO OFFSET THE DOLET HILLS UNRECOVERED**
24 **INVESTMENT?**

25 **A:** The Texas portion of the available EDFIT is \$30,408,645. This consists of \$23,000,070
26 of unprotected EDFIT and \$7,408,575 of amortized protected EDFIT.²

¹ Direct Testimony of Thomas P. Brice, p. 7, line 15 – p. 8, line 7.

² See W/P Schedule B 1.5.17.1.

1 **Q: DO YOU AGREE WITH SWEPCO'S PROPOSAL TO USE THE AVAILABLE**
2 **EDFIT BALANCES TO OFFSET THE NET INVESTMENT IN DOLET HILLS?**

3 A: No. The Company's proposal is unacceptable for several reasons. First, this proposed
4 treatment would inappropriately shift the benefits of the EDFIT balances from ratepayers
5 to shareholders, specifically to expedite the shareholders' recovery of stranded costs from
6 an early plant retirement. Many regulators, including this Commission, have recognized
7 that current ratepayers should not be forced to fund the *accelerated* recovery of the
8 stranded costs of early plant retirements required by environmental regulations or
9 policies.³ One of the key reasons is generational equity—the recognition that the entire
10 cost should not be borne by current ratepayers, but instead, that future ratepayers should
11 share in the costs of achieving a cleaner, safer environment as the future ratepayers are
12 the primary beneficiaries of the improvements. Regulators also understand that by
13 spreading the recovery of these costs into the future opportunities arise to offset some of
14 the costs with other savings. These savings can come from improved technologies,
15 increased operating efficiencies, lower capital costs, or load growth. With the passage of
16 time, rate bases that are currently inflated with environmental compliance costs have time
17 to subside to more reasonable levels. Thus far, I have yet to hear many good arguments
18 against spreading the higher costs of early plant terminations over some reasonable period
19 into the future.

20 The Company's proposal to deplete ratepayers' EDFIT balances to expedite the
21 shareholders' recovery of the Dolet Hills stranded costs is contrary to the generally
22 accepted approach for early plant retirements. A more appropriate treatment is to
23 preserve the EDFIT balances to be refunded to ratepayers, and for the Company to
24 recover the remaining balance of the plant over its original useful life. From a policy
25 perspective, the Company's proposal to accelerate its recovery of the Dolet Hills stranded
26 costs would unduly increase costs for ratepayers at a time when it is least affordable. Not
27 only have many of SWEPCO's customers suffered financially during the COVID-19

³ For example, in SWEPCO's last rate case, Docket No. 46449, the Commission rejected SWEPCO's proposal to accelerate depreciation on the early-retired Welsh 2 Unit and ordered that the Company recover the remaining costs of that plant unit over its original useful life of 24 years. The Commission also ordered that the undepreciated balance of Welsh Unit 2 be recorded in a regulatory-asset account.

1 pandemic, but the recent catastrophic weather events that occurred on and around
2 February 14, 2021 have also caused fuel costs to increase dramatically, which will put
3 further financial burdens on customers. This is simply not the appropriate time to expedite
4 the shareholders' recovery of stranded costs at ratepayers' expense.

5 **Q: WHY DO YOU SAY THAT NEW TECHNOLOGIES AND OPERATING**
6 **EFFICIENCIES CAN HELP PAY FOR EARLY PLANT TERMINATION**
7 **COSTS?**

8 A: In my experience, when the costs of early plant retirements are spread over a reasonable
9 length of time into the future, the lower costs that result from improved technologies can
10 help offset them. For example, only a few years ago solar power was more than \$200 per
11 MWH, but now it costs less than \$20 per MWH in many cases. Similarly, wind energy
12 technology cost more than \$100 per MWH, but now wind contracts are closer to \$25 per
13 MWH. Natural gas prices were \$12 per MMBtu less than 10 years ago, but now the
14 prices are closer to \$3 per MMBtu. These dramatic savings have been achieved in large
15 part by improvements in technology.

16 Operating efficiencies can also help lower costs over time. The Bureau of Labor Statistics
17 tracks these efficiency gains each year.⁴ Typically, efficiency gains average more than
18 1% per year and sometimes more than that in some sectors.⁵

19 **Q: PLEASE EXPLAIN HOW THE PASSAGE OF TIME WILL HELP OFFSET THE**
20 **EARLY PLANT TERMINATION COSTS BY ALLOWING THE CURRENTLY**
21 **INFLATED RATE BASES TO SUBSIDE TO MORE REASONABLE LEVELS.**

22 A: Utilities across the country are experiencing increased investment levels to comply with
23 environmental regulations. These abnormally high investment levels resulting from
24 environmental compliance will subside over time as the capital costs are repaid through
25 depreciation recoveries. Since one type of these environmental compliance costs is the

⁴ Labor productivity is a measure of economic performance that compares the amount of goods and services produced (output) with the number of hours worked to produce those goods and services.

⁵ For example, productivity growth for the period 2007-2015 was 1.3% for non-farm labor and 1.8% for the manufacturing sector.

1 stranded costs that result from early plant retirements, the pay-down of these costs should
2 occur over time as well. All things being equal, this will lessen the burden on ratepayers.

3 **Q: HOW CAN LOWER CAPITAL COSTS HELP OFFSET THE STRANDED**
4 **COSTS RESULTING FROM EARLY PLANT TERMINATION?**

5 A: The cost of both debt and equity is much lower than it was even just a few years ago. The
6 current cost of long-term debt is close to 4%, which is 200 basis points lower than it was
7 just a few years ago. Similarly, the cost of equity is approaching 9%, which is 100 basis
8 points lower than returns on equity typically awarded just a few years ago. These lower
9 capital costs could be used to significantly offset the higher plant-termination costs if the
10 termination costs are spread out over time. To mitigate the economic impact of these early
11 retirements and investments in new plant caused by environmental regulations, it is
12 appropriate for commissions to require that utilities spread the recovery of stranded costs
13 over time, to allow these significant cost increases to be offset with lower capital costs.
14 Further, utilities should also be encouraged to finance environmental investments more
15 with lower-cost debt to further mitigate the rate impact of these costs.

16 **Q: HOW CAN LOAD GROWTH OFFSET THE PLANT TERMINATION COSTS?**

17 A: As load grows over time, the fixed costs of the utility, including stranded asset recovery
18 costs, are spread over more kWh sales, bringing the unit cost per customer down over
19 time. This benefit increases with more prolonged recovery periods.

20 **Q: ARE THERE EXAMPLES IN WHICH THIS COMMISSION HAS REJECTED**
21 **ARGUMENTS TO ACCELERATE DEPRECIATION ON EARLY-RETIRED**
22 **PLANTS?**

23 A: Yes. In SWEPCO's last rate case, Docket No. 46449, the Commission rejected
24 SWEPCO's proposal to accelerate depreciation on the early-retired Welsh 2 and instead
25 ordered that the Company recover the remaining costs of that plant unit over its original
26 useful life, 24 years.

70. It is reasonable for SWEPCO to recover the remaining undepreciated balance of Welsh 2 over the 24-year remaining lives of Welsh Units 1 and 3.⁶

Q: ARE THERE OTHER EXAMPLES IN WHICH AEP UTILITIES HAVE BEEN ORDERED TO RECOVER ITS STRANDED PLANT BALANCES OVER LONGER AMORTIZATION PERIODS AFTER THE PLANTS ARE RETIRED?

A: Yes. American Electric Power (“AEP”) retired thirteen coal plants in 2015 across four states. As shown in the table below, all of these plants had stranded cost balances that were recovered over 25 and 30-year amortization periods in line with their originally-scheduled retirement dates. The AEP plants retired in 2015 along with their stranded cost balances and amortization periods are set forth in the table below. These longer recovery periods give regulators an opportunity to avoid implementing higher rates that would otherwise result from these early retirements to the detriment of ratepayers.

Table 2: AEP Retired Coal Units⁷					
AEP Coal Units	Date Retired	Date Amortized Through	Amort. Period (Years)	State	Balance
Tanner Creek Unit 1	2015	2044	30	Michigan	\$43.401M
Tanner Creek Unit 2	2015	2044	30	Michigan	\$43.401M
Tanner Creek Unit 3	2015	2044	30	Indiana	\$43.401M
Tanner Creek Unit 4	2015	2044	30	Indiana	\$43.401M
Big Sandy Unit 1	2015	2040	25	Kentucky	\$92.491M
Big Sandy Unit 2	2015	2040	25	Kentucky	\$92.491M
Kawona River Units 1-2	2015	2040	25	W Virginia	\$43.924M
Sporn Unit 1	2015	2040	25	W Virginia	\$6.982M
Sporn Unit 3	2015	2040	25	W Virginia	\$6.982M
Glen Lyn Unit 5	2015	2040	25	W Virginia	\$3.703M
Glen Lyn Unit 6	2015	2040	25	W Virginia	\$3.703M
Clinch River Units 1-2	2015	2040	25	W Virginia	\$8.211M
Clinch River Units 3	2015	2040	25	W Virginia	\$56.967M
Total Stranded Costs					\$489.065M

⁶ See Final Order in Docket No. 46449.

⁷ Provided by AEP-PSO in PSO’s Oklahoma 2015 rate case, Cause No. PUD 201500208, in response to OIEC Data Request 17-2.

1 **Q: HAVE OTHER JURISDICTIONS DENIED ACCELERATED RECOVERY**
2 **WITH RESPECT TO AEP AFFILIATED PLANT RETIREMENTS?**

3 A: Yes. In its 2015 rate case in Oklahoma, AEP-Public Service Company of Oklahoma
4 ("PSO") sought approval to retire its two coal units pursuant to a Regional Haze plan.⁸
5 Under PSO's plan, PSO would retire Northeastern 4 in 2016 and Northeastern 3 in 2026.⁹
6 PSO sought approval in its rate case application to accelerate the depreciation of both
7 units so that the entire cost of the plants would be recovered by 2026 when the second
8 unit was retired. The request would have increased rates by about \$13M per year.
9 Oklahoma Commission Staff, the Attorney General, the Oklahoma Industrial Energy
10 Consumers ("OIEC") and the Department of Defense ("DOD") all opposed the
11 recommendation. In its final order, the Oklahoma commission rejected PSO's proposal
12 to increase depreciation rates to recover the entire costs of the plants by the early
13 retirement date in 2026.¹⁰

14 The Commission finds that PSO should be denied cost recovery for the
15 accelerated depreciation that PSO seeks to recover for Northeastern Units
16 3 and 4 over the 2016 to 2026 period and that to mitigate rate increases,
17 depreciation for the undepreciated, "original" costs of these two units
18 should continue on its current pace to 2040.

19 **Q: ARE THERE EXAMPLES FROM OTHER NEIGHBORING STATES IN WHICH**
20 **UTILITIES ARE RECOVERING STRANDED COAL PLANT BALANCES**
21 **OVER AMORTIZATION PERIODS THAT EXTEND BEYOND THE PLANTS'**
22 **EARLY RETIREMENT DATES?**

23 A: Yes. In New Mexico, Public Service Company of New Mexico ("PNM") agreed to write-
24 off 50% of the stranded costs associated with two coal units retired as part of its plan to
25 comply with the Regional Haze Rule.¹¹ One of PNM's coal facilities, the San Juan
26 Generating Station ("SJGS"), consists of four coal-fired units with 1,683 net megawatts
27 ("MW") of electric generation capacity. PNM's State Implementation Plan ("SIP")

⁸ Cause No. PUD 201500208.

⁹ *Id.*

¹⁰ Final Order in Cause No. PUD 201500208 at p. 5.

¹¹ The federal Regional Haze Rule was issued by the U. S. Environmental Protection Agency ("EPA") under the Clean Air Act ("CAA").

sought approval to (a) abandon San Juan Units 2 and 3 and (b) issue Certificates of Public Convenience and Necessity ("CCN") for replacement power resources. As part of the settlement in that case, PNM agreed to write-off 50% of the stranded book value of the plant assets at retirement and place the remaining balance in a regulatory asset account when the plant is retired and recover that balance over a 20-year amortization period. The stipulation language is set forth below:

Undepreciated Investment in Retired Plant

18. PNM shall be allowed to recover 50% of its undepreciated investment in SJGS Units 2 and 3 as shown on its books as of December 31, 2017, after reducing the net book value of SJGS Unit 3 by \$26 million to reflect the value placed on the additional SJGS Unit 4 capacity. Until that time, PNM shall continue to depreciate SJGS Units 2 and 3 according to its approved depreciation schedules. Based on current projections, PNM estimates its undepreciated investment in SJGS Units 2 and 3 will be approximately \$257.0 million at December 31, 2017. Based on this estimate, PNM will be allowed to recover 50% of the undepreciated investment estimated at \$115.5 million, which is \$257.0 million less \$26.0 million transferred to Unit 4, i.e., \$231.0 million, multiplied by 50% as the percentage of recovery agreed to in this Stipulation. PNM shall place the amount of undepreciated investment allowed to be recovered in a regulatory asset which shall be amortized over a twenty year period with a carrying charge equal to PNM's pretax weighted average cost of capital ("WACC") (as it may be modified from time to time by Commission orders in rate cases) on the unamortized amount.¹²

Q: WHAT ARE THE ARGUMENTS FOR ACCELERATING THE RECOVERY OF THESE EARLY RETIREMENTS?

A: Some utilities argue that the useful life of the plant slated for early retirement should be the retirement date, and depreciation should be recovered over the new shortened useful life of the plant. This argument has no merit. In the situation of an *early* retirement, the remaining un-depreciated plant balance (*i.e.*, the stranded costs) as of the early retirement date are transferred into a regulatory asset account to be recovered over any period of

¹² See Stipulation filed October 1, 2014 in Case No. 13-00390-U at p. 6 (Emphasis added).

1 time the regulators deem appropriate. Once the asset balance has been transferred to a
2 regulatory asset account, the depreciation rules no longer apply.¹³

3 **Q: HAS THE COMPANY MADE SUCH ARGUMENTS IN THIS CASE?**

4 A: Yes. At page six of his direct testimony, Mr. Brice provides the following:

5 **Q. ACCORDING TO GENERALLY ACCEPTED ACCOUNTING PRINCIPLES**
6 **(GAAP) AND STANDARD REGULATORY PRACTICE, OVER WHAT TIME**
7 **PERIOD WILL THE REMAINING UNDEPRECIATED VALUE OF DOLET**
8 **HILLS BE DEPRECIATED?**

9 A. Consistent with GAAP and standard regulatory practice, the remaining undepreciated
10 value of Dolet Hills will be depreciated through 2021. SWEPCO realizes that
11 depreciation of Dolet Hills over its 2021 economically useful life for ratemaking purposes
12 would have a significant impact on SWEPCO's base rates that are to be set in this
13 proceeding.

14 Unfortunately, Mr. Brice is incorrect on both accounts. Neither GAAP nor standard
15 regulatory practice supports the Company's proposed treatment of accelerated
16 depreciation of an early plant retirement. Instead, the proper *accounting treatment* would
17 be to move the unrecovered Dolet Hills balance at retirement to a regulatory asset account
18 and to recover that balance over whatever period the commission deems appropriate. The
19 "*standard regulatory practice*" is the same, as shown in the examples above.

20 **Q: HAS THIS COMMISSION DETERMINED THE APPROPRIATE**
21 **ACCOUNTING TREATMENT FOR EARLY-RETIRED PLANT?**

22 A: Yes. As discussed earlier, in SWEPCO's last rate case, Docket No. 46449, the
23 Commission rejected SWEPCO's proposal to accelerate depreciation on the early-retired
24 Welsh 2 unit and ordered that the Company recover the remaining costs of that plant unit
25 over its original useful life -- 24 years. The Commission also set forth the appropriate
26 accounting treatment for such plant in its final order.

¹³ The depreciation rules only apply to plant in service, not to plant that is no longer in service.

1 71. The appropriate accounting treatment that results in the
2 appropriate ratemaking treatment is to record the undepreciated balance
3 of Welsh Unit 2 in a regulatory-asset account.

4 The Commission put the stranded balance of the Welsh 2 unit in a regulatory asset
5 account so it could be removed from rate base and recovered over whatever period the
6 Commission deemed reasonable, and not over the artificially shortened life of the plant.¹⁴

7 **Q: WHAT IS YOUR RECOMMENDATION FOR THE RECOVERY OF THE**
8 **DOLET HILLS PLANT?**

9 A: I recommend that the unrecovered Dolet Hills investment *not* be offset with the available
10 EDFIT and instead be depreciated using the currently-approved depreciation rates.

11 **Q: WHAT IS YOUR RECOMMENDATION FOR THE REFUND OF THE**
12 **AVAILABLE EDFIT?**

13 A: I recommend that the available EDFIT be refunded to customers over a 4-year period.
14 This corresponds with SWEPCO's rate case 4-year rate case cycle.

15 **Q: WHAT IS THE AMOUNT OF THE ANNUAL AMORTIZATION OF THE**
16 **AVAILABLE EDFIT?**

17 A: The annual amortization is a ratepayer credit of \$7,602,161 to Texas ratepayers. This
18 adjustment is found on Exhibit MG-2.10.

19 **Q: WHAT IS THE ADJUSTMENT TO RETAIN THE CURRENT DEPRECIATION**
20 **RATES FOR DOLET HILLS?**

21 A: The adjustment necessary to retain the current depreciation rates for Dolet Hills reduces
22 the Company's proposed depreciation expense by \$1,909,171 on a total Company basis,
23 or \$705,313 for the Texas jurisdiction. This adjustment is found on Exhibit MG-2.9. The
24 combination of these adjustments is an annual rate reduction of \$8,307,474 for ratepayers,
25 with no harm to the Company's financial position.

¹⁴ See Proposal for Decision in Docket No. 46449 at pages 93-94.

1 **Q: DO YOU HAVE ANY FURTHER RECOMMENDATIONS RELATED TO**
2 **DOLET HILLS?**

3 A: Yes. Once the plant is retired at the end of 2021, it will no longer be *used and useful* and
4 should not be included in rate base earning a return at that point. In its decision on the
5 Welsh 2 plant in SWEPCO's last rate case, the Commission was clear on this point.

6 Under PURA, a utility may earn a return only on invested capital that is
7 "used and useful in providing service to the public." The Commission
8 rules are in accord, providing that a major component of rate base is:
9 "Original cost, less accumulated depreciation, of electric utility plant used
10 by and useful to the electric utility in providing service."¹⁵

11 In that case, the Commission removed the remaining balance of the early-retired Welsh
12 2 plant from rate base and collected the remaining balance from ratepayers over the useful
13 life of the plant before retirement. This treatment allowed a return of the undepreciated
14 remaining balance, but not a return on the balance once the plant was no longer being
15 used to serve ratepayers. In its final order the Commission specifically stated:

16 68. Because Welsh Unit 2 is no longer used and useful, SWEPCO may not
17 include its investment associated with the plant in its rate base, and may
18 not earn a return on the remaining investment.

19 In other words, even though the Commission found that the Welsh 2 early retirement was
20 a prudent decision, the appropriate ratemaking treatment was to exclude the remaining
21 Welsh 2 balance from rate base recovery because it was no longer used and useful.

22 **Q: SINCE THE PLANT IS BEING RETIRED AT THE END OF 2021, BETWEEN**
23 **RATE CASES, HOW CAN THE COST SAVINGS ASSOCIATED WITH**
24 **REMOVING THE PLANT FROM RATE BASE BE PASSED ON TO**
25 **RATEPAYERS?**

26 A: The Commission should order the establishment of a regulatory liability to accumulate
27 the return on the remaining balance of the Dolet Hills plant at the time of its retirement.
28 This regulatory liability would accrue the Dolet Hills return for the years 2022, 2023,
29 2024 and 2025 until new rates from the Company's next rate case in its scheduled 4-year

¹⁵ See Proposal for Decision in Docket No. 46449 at page 90.

1 cycle go into effect. In the next rate case, the regulatory liability would be returned to
2 ratepayers over the 4-year rate-effective period for the next rate case.

3 **Q: IS THIS RECOMMENDATION CONSISTENT WITH THE TREATMENT OF**
4 **DOLET HILLS COSTS BEING RECOMMENDED BY OTHER CARD**
5 **WITNESSES?**

6 A: Yes. CARD witness Scott Norwood is recommending that the certain Dolet Hills
7 operating and maintenance expenses that will be reduced or eliminated with the plant's
8 retirement be returned to ratepayers which, could be accomplished by using the same
9 regulatory liability account.

10 **Q: PLEASE SUMMARIZE YOUR RECOMMENDATIONS RELATED TO THE**
11 **DOLET HILLS RETIREMENT.**

12 A: I make the following recommendations related to the Dolet Hills retirement:

- 13 1. The Company's proposal to use ratepayers' EDFIT money to pay down the
14 remaining net balance of the Dolet Hills plant should be rejected.
- 15 2. The Company's proposal to accelerate depreciation on the plant to recover the
16 remaining balance after the EDFIT offset should be rejected.
- 17 3. The current depreciation rates for the Dolet Hills plant should be maintained, as
18 they were with the Welsh 2 early retirement; this will eliminate any need to use
19 EDFIT or accelerated depreciation to recover the balance.
- 20 4. A regulatory liability should be established to accumulate the rate base return
21 collected from ratepayers each year on the Dolet Hills balance after the plant
22 retires until the Company's next rate case. This will ensure that ratepayers are not
23 paying a return on plant that is no longer used and useful.
- 24 5. The regulatory liability used to refund the Dolet Hills return to ratepayers after
25 the plant is no longer used and useful can also be used to return O&M costs that
26 will not be incurred after the plant retires.

27 **Q: PLEASE SUMMARIZE YOUR RECOMMENDATIONS RELATED TO EDFIT**
28 **AMORTIZATION.**

29 A: I make the following recommendations related to EDFIT:

1 1. I recommend that the EDFIT balances available for amortization, which would
2 include the unprotected EDFIT and the protected EDFIT for which the ARAM
3 period has already passed, should not be used to recover the stranded Dolet Hills
4 plant balances.

5 2. I recommend that the available EDFIT be returned to ratepayers over a 4-year
6 period to coincide with the Company's scheduled rate case cycle.

7 **IV. EMPLOYEE COMPENSATION EXPENSE ADJUSTMENTS**

8 **A. SHORT TERM ANNUAL INCENTIVE COMPENSATION EXPENSE**

8 **Q: PLEASE PROVIDE A BRIEF DESCRIPTION OF AEP/SWEPCO'S ANNUAL**
9 **INCENTIVE COMPENSATION PLANS.**

10 A: AEP/SWEPCO's incentive compensation plans are formal, written plans approved by
11 senior management. In total, there are four annual incentive plans under which SWEPCO
12 and AEPSC employees may be compensated. Each of these plans is governed by an
13 earnings per share ("EPS") funding mechanism that determines if and to what extent the
14 plans are funded each year.

15 **Q: PLEASE DESCRIBE THE INCENTIVE COMPENSATION COSTS**
16 **REQUESTED BY THE COMPANY.**

17 A: SWEPCO (1) adjusted its test year levels for short term incentives down to their target
18 levels (which represents market levels); (2) removed that portion of the plan costs based
19 directly on financial goals; and (3) further adjusted the plan costs for the anticipated
20 financial funding component of the plans.¹⁶ SWEPCO is requesting the recovery of
21 \$5,933,784 for its annual incentive plan.¹⁷ The AEPSC annual incentive plan costs were
22 similarly adjusted, with \$3,454,378 of expenses included in the revenue requirement.¹⁸

¹⁶ Direct Testimony of Michael A. Baird, p. 21, line 15 – p. 22, line 3.

¹⁷ *Id* at p. 22, line 6.

¹⁸ See BJF-18 (print entire workbook).xlsx, tab 2, cell K74.

1 **Q: WHAT IS THE APPROACH USED BY THIS COMMISSION WHEN A**
2 **UTILITY'S INCENTIVE PLAN HAS A FINANCIAL FUNDING MECHANISM?**

3 A: In a recent Southwestern Public Service Company ("SPS") rate case, Docket No. 43695,
4 the Texas PUC disallowed 100% of short-term incentives directly tied to financial
5 performance measures and 50% of the remaining incentives because they were indirectly
6 tied to financial performance through an earnings-per-share funding mechanism.¹⁹ The
7 Commission reaffirmed this treatment in SWEPCO's previous rate case, Docket No.
8 46449, where the Commission adopted Staff's recommendation, which followed the
9 precedent established in the SPS case and applied it to SWEPCO's incentives. In the
10 SWEPCO rate case, the adjustment to take out 50% of the indirect incentives was reduced
11 to 37.5%, which was consistent with the treatment in the SPS case because this adjustment
12 properly removed 50% of SWEPCO's 75% funding mechanism at the time, compared to
13 the 100% funding mechanism utilized by SPS.

14 **Q: DID THE COMPANY FOLLOW THE COMMISSION'S PRECEDENT IN THIS**
15 **CASE?**

16 A: It appears the Company attempted to follow the precedent for the most part, however
17 there is a discrepancy that must be addressed. The Company removed the incentive costs
18 *directly* related to financial performance, and removed 35% of the remaining incentives,
19 which represents 50% of the Company's *anticipated* 70% funding mechanism. The
20 discrepancy I note relates to the difference between the anticipated and actual funding
21 threshold in place during the test year.

22 **Q: PLEASE EXPLAIN.**

23 A: SWEPCO's witness Michael Baird states that the financial funding is based on the
24 anticipated financial funding component.²⁰ However, the Company actually used a
25 different level of financial funding during the test year. Although AEP used a funding
26 requirement of only 70% in 2019, it changed to a full financial Earnings Per Share

¹⁹ See Docket No. 43695, Order on Rehearing at pp. 5-6.

²⁰ Direct Testimony of Michael A. Baird, p. 21, line 22 – p. 22, line 1.

1 (“EPS”) threshold of 100% for 2020 because of the uncertainty related to COVID-19.²¹
2 Because the actual financial funding mechanism for the rate effective period is 100%
3 rather than 70%, I recommend that this discrepancy be corrected to remain consistent
4 with the Commission’s established treatment of disallowing 50% of the indirect
5 financially-based incentives associated with the funding mechanism.

6 **Q: COMPANY WITNESS ANDREW R. CARLIN DESCRIBES THE 100% EPS**
7 **FUNDING MECHANISM CHANGE AS TEMPORARY.²² DOES THIS**
8 **ASSERTION CHANGE YOUR RECOMMENDATION?**

9 A: No. The Commission’s treatment of removing all direct financially-based incentive costs
10 and 50% of the indirect financial incentive costs should be followed based upon the actual
11 test year and the rate effective period. Mr. Carlin states:

12 The funding mechanism ensures the Companies can afford employee
13 incentive compensation while also meeting their commitments to other
14 stakeholders and that STI compensation does not impair the Companies
15 financially.²³

16 This statement shows that the Company changed the 2020 annual incentive plan mid-year
17 out of financial concerns, and serves to further illustrate the extent to which the financial
18 incentive plan is discretionary. Senior management is free to alter the payout levels and
19 formulas in any manner considered necessary to protect shareholders’ interests. For this
20 reason, it is appropriate to calculate the sharing of incentive costs between ratepayers and
21 shareholders based upon the *actual* mechanism adopted during the test year, rather than
22 the *anticipated* funding mechanism which was not actually implemented.

23 **Q: DOES THE COMPANY’S INCENTIVE PLAN SPECIFICALLY ALLOW FOR**
24 **DISCRETIONARY CHANGES LIKE THE ONE MADE IN 2020?**

25 A: Yes. The full discretion of management has always been a feature of the Company’s
26 incentive plans. The 2019 annual incentive plan included the following language:

²¹ Direct Testimony of Andrew R. Carlin, p. 31, line 10 – p. 32, line 2.

²² *Id.*, p. 31, lines 16-18.

²³ *Id.*, p. 32, lines 5-7.

1 All incentive plan funding is contingent on AEP achieving operating
2 earnings of at least \$3.95 per share for 2019.²⁴

3 The 2020 plan included similar language:

4 All incentive plan funding is contingent on AEP achieving Operating EPS
5 of at least \$4.25 for 2020.²⁵

6 It clear that the AEP annual incentive plans currently have a 100% financial performance
7 requirement to be funded.

8 **Q: WHAT IS YOUR RECOMMENDATION REGARDING THE FINANCIAL**
9 **FUNDING COMPONENT ADJUSTMENT OF THE SWEPCO INCENTIVE**
10 **PLAN EXPENSES?**

11 A: I recommend that the Commission recognize that 100% of the annual incentive plans
12 funding is based on the Company's financial performance and exclude 50% of the
13 otherwise recoverable incentive plan costs, to be consistent with prior precedent.

14 **Q: WHAT IS THE AMOUNT OF THE ADJUSTMENT YOU RECOMMEND TO**
15 **ANNUAL INCENTIVE PLAN COST?**

16 A: I recommend that the expenses for the SWEPCO annual incentive plan be reduced by
17 \$2,187,400 on a total company basis, or \$856,586 for the Texas retail jurisdiction. I
18 further recommend that the related payroll taxes be reduced by \$55,381 for the Texas
19 retail jurisdiction. These adjustments can be found on Exhibit MG-2.3.

20 **Q: DO YOU RECOMMEND THE SAME ADJUSTMENT FOR THE AEPSC**
21 **INCENTIVE COSTS ALLOCATED TO SWEPCO?**

22 A: Yes. The AEPSC adjustment was sponsored by Brian J. Frantz and included similar
23 adjustments to reduce the incentive expenses to the target level, then removed incentives
24 with direct financial goals, and then excluded part of the remaining incentive costs for the
25 financial funding requirements.²⁶ The AEPSC adjustment did not remove 50% of all of

²⁴ See OPUC_1-18_Attachment 1, page 2.

²⁵ See OPUC_1-18_Attachment 2, page 2.

²⁶ Direct Testimony of Brian J. Frantz, p. 72, lines 7-11.

1 the incentives even though all of the annual incentive plan expenses have an EPS
2 threshold for funding.

3 **Q: WHAT IS THE AMOUNT OF THE ADJUSTMENT YOU RECOMMEND TO**
4 **EXCLUDE 50% OF THE AEPSC ANNUAL INCENTIVE PLAN COSTS WITH A**
5 **FINANCIAL BASED FUNDING REQUIREMENT?**

6 A: I recommend that the AEPSC annual incentive plan expenses be reduced by \$998,579 on
7 a total Company basis, or \$391,044 for the Texas retail jurisdiction to exclude 50% of all
8 incentives with a financially-based funding requirement. This adjustment can be found
9 on Exhibit MG-2.4.

10 **Q: MR. CARLIN ARGUES THERE IS MERIT TO THE COMMISSION**
11 **RECONSIDERING ITS PRACTICE OF EXCLUDING FINANCIAL-BASED**
12 **INCENTIVES. DO YOU AGREE?**

13 A: No. I believe the Commission's long-standing policy of excluding financially-based
14 incentive compensation is appropriate because it balances the interests of customers and
15 shareholders. There is no doubt that financial-based incentives provide more of a direct
16 benefit to shareholders. As a result, shareholders should bear the costs of these incentives.

17 **Q: WHAT IS THE GENERAL RATIONALE FOR EXCLUDING INCENTIVE**
18 **COMPENSATION TIED TO FINANCIAL PERFORMANCE?**

19 A: In most jurisdictions, the cost of incentive plans which are tied to financial performance
20 measures are excluded for ratemaking purposes. When the costs associated with these
21 plans are excluded, the *primary* rationale is that financially-based incentives benefit
22 shareholders more than they do ratepayers. Other rationales used by the regulators are:

23 **(1) Payment is uncertain.** Often, as is the case here, payment of incentive
24 compensation is conditioned upon meeting a predetermined financial goal such as
25 achieving a certain increase in earnings, reaching a targeted stock price or meeting
26 budget objectives. If the predetermined goals are not met, the incentive payment
27 is not made, or payment is made at some lesser amount. Therefore, one cannot
28 know from year to year what the level of the payment may be or whether the

1 payment will be made at all. It is generally considered inappropriate to set rates
2 to recover a tentative level of expense.²⁷

3 **(2) Many of the factors that significantly impact earnings are outside the control**
4 **of most company employees and have limited value to customers.** For
5 example, an unusually hot summer can easily trigger an incentive payment based
6 on company earnings for an electric utility, as a cold winter can for a gas utility.
7 Obviously, weather conditions are outside the control of utility employees and
8 customers receive no benefit from the higher utility bills that result from an
9 unusually hot or cold weather. Similarly, company earnings may increase, thus
10 triggering incentive payments, as a result of customer growth, which commonly
11 occurs without significant influence from company personnel. In fairness, since
12 shareholders enjoy the benefits of customer growth between rate cases,
13 shareholders should also bear the cost of any incentive payments such growth may
14 trigger. Finally, utility earnings may increase substantially if the utility is able to
15 successfully argue for a higher ROE in a rate case proceeding. Utility efforts to
16 maximize ROE in a rate proceeding, however, have little to do with improving
17 overall employee performance across the company. If utility employees gear their
18 efforts toward securing an *unreasonably* high ROE in a rate proceeding, the
19 incentive mechanism actually would work to the detriment of the utility
20 customers.

21 **(3) Earnings-based incentive plans can discourage conservation.** When incentive
22 payments are based on earnings, employees may not support conservation
23 programs designed to reduce usage if they perceive these programs could
24 adversely impact incentive payment levels. To the extent that earnings-based
25 incentive plans discourage conservation and demand-side management programs,
26 these plans do not serve the public interest. The growing focus on energy
27 efficiency at both the national and state level renders this point especially
28 important.

29 **(4) The utility and its stockholders assume none of the financial risks associated**
30 **with incentive payments.** Ratepayers assume the risk that the utility will instead
31 retain the amounts collected through rates for incentive payments whenever
32 targeted increases are not reached. Employees assume the risk that the incentive
33 payments will not be made in a given year. The utility and its stockholders,

²⁷ PSO's experience with its 2008 rate case proceeding, in Oklahoma PUD 2008-00144, is a good example of this problem. In 2009, PSO's below target EPS reduced the funding available for incentive compensation payments by 76.9%. Although in PSO's 2008 rate case, the Oklahoma Commission had included more than \$4 million in rates for incentives, PSO chose not to use all of that money to pay incentives but instead retained some of those funds for its shareholders to help bolster the Company's lower earnings that year.

1 however, assume no risk associated with these payments. Instead, the company's
2 only responsibility is to decide who gets the money, the stockholders or the
3 employees.²⁸

4 **(5) Incentive payments based on financial performance measures should be**
5 **made out of increased earnings.** Whatever the targets or goals may be that
6 trigger an incentive payment, when the plan is based in whole or in part on
7 financial performance measures the company always obtains a financial benefit
8 from achieving these objectives. This financial benefit should provide ample
9 funds from which to make the payment. If not, the incentive plan was poorly
10 conceived in the first place. As such, employees should be compensated out of
11 the increased earnings, and not through rates.

12 **(6) Incentive payments embedded in rates shelter the utility against the risk of**
13 **earnings erosion through attrition.** When utilities are allowed to embed
14 amounts for incentive payments in rates, that money is available to the utility not
15 only to pay the incentive payment when financial performance goals are met but
16 also to supplement earnings in those years when the company does not perform
17 well. In those years when financial performance measures are met, the increased
18 earnings of the company provide ample additional funds from which to make the
19 incentive payments to employees, and the incentive payment amount embedded
20 in rates is not needed. In those years when financial performance measures are
21 not met and the incentive payments are not made, the amount embedded in rates
22 for incentive payments acts as a financial hedge to shelter the poor financial
23 performance of the company.

24 **Q: HOW DOES THE TREATMENT OF SHORT-TERM INCENTIVE COSTS IN**
25 **TEXAS COMPARE WITH OTHER JURISDICTIONS' TREATMENT OF**
26 **INCENTIVE COMPENSATION?**

27 A: The policy of excluding a portion of short-term compensation is consistent with the
28 majority of jurisdictions. I have more than 25 years of experience in numerous
29 jurisdictions testifying in regulatory proceedings involving annual incentive
30 compensation plans. In conjunction with my work in this area, I have conducted an
31 Incentive Compensation Survey of the 24 Western States, which has been taken by the
32 Garrett Group in 2007, and updated in 2009, 2011, 2015 and 2018. The results show that
33 a clear majority of the states surveyed follow the financial-performance rule, in which

²⁸ *Id.*

incentive payments associated with financial performance are excluded from rates. While some states disallow incentive pay using other criteria, and some states apply a sharing mechanism such as a 50%-50% allocation, none of the jurisdictions surveyed allow full recovery of incentive compensation through rates as a general rule. The table below provides a summary of the survey results:

Garrett Group, LLC 24 Western State Incentive Survey Results			
No Incentive Costs Allowed in Rates	Financial Performance Rule Followed	Other Sharing Approach	Incentives Not at Issue
Hawaii			
	Arizona		
	Arkansas		
	California		
	Idaho		
	Kansas		
	Louisiana		
	Minnesota		
	Missouri		
	Nebraska		
	Nevada		
	New Mexico		
	North Dakota		
	Oklahoma		
	Oregon		
	South Dakota		
	Texas		
	Utah		
	Washington ²⁹		
	Wyoming		
		Alaska ³⁰	
		Colorado ³¹	
			Iowa
			Montana

As shown in the table above, most states disallow incentive compensation costs tied to financial measures. A summary of these survey results is attached as Exhibit MG-3.

²⁹ Washington has generally excluded a portion of financial-based incentives.

³⁰ Incentive compensation has not been an issue in the past, partly because most utilities in Alaska are municipalities and Co-ops. In one recent case, however, the Commission approved incentives in rates, which may turn out to be an anomaly.

³¹ Colorado followed the financial performance rule in the past. In one recent case, however, the Commission approved another approach, which may also be an anomaly.

1 **Q: IN YOUR EXPERIENCE, WHEN REGULATORS EXCLUDE THE PORTION**
2 **OF A UTILITY'S INCENTIVE PLAN TIED TO FINANCIAL PERFORMANCE**
3 **MEASURES, DOES THE UTILITY STOP OFFERING INCENTIVE**
4 **COMPENSATION TO HELP ACHIEVE ITS FINANCIAL GOALS?**

5 A. No. Even though regulators generally disallow incentive compensation tied to financial
6 performance for ratemaking purposes, utilities continue to include financial performance
7 as a key component of their plans. In my opinion, utilities continue to tie incentive
8 payments to financial performance because by doing so they achieve the primary
9 objective of the incentive plans: to increase corporate earnings and, thereby, earnings per
10 share (EPS). However, since the utility retains the increased earnings these plans help
11 achieve, payments for the plans should be made from a portion of these increased
12 earnings. Thus, properly designed incentive compensation plans need not be subsidized
13 by ratepayers.

14 **Q: WILL AEP BE FINANCIALLY HARMED FROM YOUR RECOMMENDATION**
15 **TO EXCLUDE ALL FINANCIALLY-BASED INCENTIVE COMPENSATION**
16 **PAYMENTS?**

17 A: No. AEP/SWEPCO's incentive compensation payments are discretionary payments
18 limited by the Company's financial performance funding mechanism. This funding
19 mechanism ensures that the incentive payments are not made at the expense of the
20 Company's EPS goals. In those years when the EPS targets are achieved, the additional
21 funds needed to make the incentive payments to employees will have been made available
22 through the increased earnings that resulted from reaching these EPS goals.

23 **Q: WHAT RATIONALE DO UTILITIES PROVIDED FOR INCLUDING ANNUAL**
24 **INCENTIVE PLAN IN RATES?**

25 A: Utilities generally argue that incentives are part of an overall compensation package that
26 is designed to attract and retain qualified personnel. Since other utilities offer incentive
27 plans to their employees, the company would run the risk of not being able to compete
28 for key personnel if it did not offer a comparable plan.

1 **Q: IS THIS ARGUMENT PLAUSIBLE?**

2 A: No. The problem with the Company's argument is that when utilities such as SWEPCO
3 compete with other utilities for qualified personnel, and the incentive compensation plans
4 of these other utilities are being reduced, for ratemaking purposes, for the portion of the
5 plans tied to financial performance, SWEPCO is not put at a competitive disadvantage
6 when its incentive compensation costs are similarly reduced.

7 Further, when incentive payments are based on financial performance goals, there should
8 be a financial benefit to the company that comes from achieving these goals and this
9 financial benefit should provide ample additional funds from which to make the incentive
10 payments. Thus, a utility is not placed at a competitive disadvantage when incentive
11 payments tied to financial performance are not collected through rates.

12 **B. LONG-TERM EXECUTIVE STOCK INCENTIVE PLAN**

13 **Q: WHAT HAS SWEPCO PROPOSED WITH RESPECT TO THE RECOVERY OF**
14 **LONG-TERM STOCK INCENTIVE PLAN FOR EXECUTIVES?**

15 A: The Company is proposing to recover \$1,025,993, or \$371,024 for the Texas retail
16 jurisdiction, for its long-term incentive plan costs.

17 **Q: PLEASE DESCRIBE THE COMPANY'S LONG-TERM COMPENSATION**
18 **PLANS.**

19 A: In addition to the company-wide incentive plans discussed above, executives and
20 managers of the Company are provided Long-Term Incentive Plan ("LTIP")
21 compensation. The LTIP awards are composed of *performance units* and *restricted stock*
22 *units* (RSUs). The performance units are granted based on three performance measures:
23 (1) three-year total shareholder return; (2) three-year cumulative operating earnings per
24 share (EPS) which is measured relative to a target set by AEP's board of directors; and
25 (3) non-emitting generating capacity.³²

³² See Direct Testimony and Exhibits of Andrew Carlin, page 43.

1 SWEPCO has excluded a portion of the LTI performance units because these awards are
2 tied to financially-based performance targets.³³ However, SWEPCO seeks to recover the
3 costs associated with RSUs because the Company asserts that they are not based on any
4 performance measures.³⁴

5 **Q: DO YOU AGREE THAT RESTRICTED STOCK UNITS ARE NOT TIED TO**
6 **FINANCIAL PERFORMANCE OF THE COMPANY?**

7 A: No. RSUs are tied to financial performance because the value of the RSU is directly tied
8 to the value of the Company's common stock. The RSUs granted to employees vest over
9 three vesting dates, which are slightly more than one, two, and three years after the grant
10 date. Dividend credits are awarded as additional RSUs when a dividend is paid on AEP
11 common stock. Like performance stock units, RSUs are tied to financial performance
12 measures since the value of the compensation the employees receive is tied to the
13 appreciation of AEP's stock price over the vesting period. As such, both elements of the
14 Company's Long-Term Incentive Plan (performance units and RSUs) are designed to
15 align the interest of AEP's management with the interest of shareholders and to promote
16 the financial success and growth of AEP.

17 **Q: WHAT IS THE RATIONALE FOR EXCLUDING ALL FINANCIALLY-BASED**
18 **LONG-TERM INCENTIVE COMPENSATION EXPENSE?**

19 A: Incentive compensation payments to officers, executives and key employees of a utility
20 are generally excluded for ratemaking purposes. Since officers of any corporation have
21 fiduciary duties of loyalty and care to the corporation itself and not to the customers of
22 the company, these individuals are required to put the interests of the company first.
23 Undoubtedly, the interests of the company and the interests of the customer are not always
24 the same, and at times, can be quite divergent. This natural divergence of interests creates
25 a situation where not every cost associated with executive compensation is presumed to
26 be a necessary cost of providing utility service. Most regulators are inclined to exclude

³³ See Direct Testimony and Exhibits of Andrew Carlin, page 41, lines 1-9.

³⁴ *Id.*

1 executive bonuses, incentive compensation and supplemental benefits from utility rates,
2 understanding that these costs would be better borne by the utility shareholders.

3 Further, long-term executive incentive plans are specifically designed to tie executive
4 compensation to the financial performance of the company. This is done to further align
5 the interest of the employee with those of the shareholder. Since the compensation of the
6 employee is tied over a long period of time to the company's stock price, it motivates
7 employees to make business decisions from the perspective of long-term shareholders.
8 This intentional alignment of employee and shareholder interests means the costs of these
9 plans should be borne solely by the shareholders. It would be inappropriate to require
10 ratepayers to bear the costs of incentive plans designed to encourage employees to put
11 the interests of the shareholders first. It has been my experience that some utilities treat
12 long-term executive incentive compensation costs as a below-the-line item even without
13 a Commission order directing them to do so.

14 **Q: SHOULD LONG-TERM INCENTIVE COMPENSATION BE RECOVERED IN**
15 **RATES IF IT IS INCLUDED AS PART OF A "MARKET-COMPETITIVE**
16 **TOTAL COMPENSATION" PLAN?**

17 A: No. Utilities often argue that executive incentives are part of an overall compensation
18 package that is designed to attract and retain qualified personnel. They claim that since
19 other utilities offer incentive plans to their executives, a company would run the risk of
20 not being able to compete for key personnel if it did not offer a comparable plan.³⁵

21 **Q: DO YOU AGREE WITH THIS ARGUMENT?**

22 A: No. When utilities, such as AEP/SWEPCO, compete with other utilities for qualified
23 executives, and the executive incentive compensation plans of those other utilities are not
24 being recovered through rates, AEP/SWEPCO is not placed in a competitive
25 disadvantage when its executive incentive compensation is excluded as well. Since most
26 states exclude executive incentive pay as a matter of course, AEP/SWEPCO would
27 actually be given an unfair advantage if its executive plans were included in rates. The
28 fact that other utilities offer executive incentive plans is not relevant; what is relevant is

³⁵ See for example, Direct Testimony and Exhibits of Andrew Carlin, page 36, line 22 through page 37, line 4.

1 the fact that other utilities are not recovering the costs of these plans in rates. In an order
2 disallowing Nevada Power's long-term incentive plan, the Nevada Commission
3 articulated this important ratemaking concept as follows:

4 Therefore, the Commission accepts BCP's and SNHG's
5 recommendations to disallow recovery of expenses associated with
6 LTIP. Both parties provide a valid argument that this type of
7 incentive plan is mainly for the benefit of shareholders. Further,
8 both BCP and SNHG provide examples of numerous other
9 jurisdictions that do not allow the recovery of these costs and,
10 therefore, disallowance in this instance would not place NPC in a
11 competitive disadvantage.³⁶ (Emphasis added).

12 **Q: WHAT IS THIS COMMISSION'S POLICY REGARDING THE RATEMAKING**
13 **TREATMENT OF LONG TERM INCENTIVE COMPENSATION?**

14 A: The Texas PUC has consistently held that financially-based annual and long-term
15 incentives are excluded for ratemaking purposes. In an Entergy Texas, Inc. (ETI) rate
16 case, PUC Docket No. 40295, the Commission disallowed rate case expenses associated
17 with ETI's attempt to recover financially-based long-term incentives:

18 Specifically, the Commission agrees with the ALJ that reductions
19 should be made to Entergy's recoverable rate-case expenses for
20 Entergy attempting to recover financially-based incentive
21 compensation in base rates. The Commission has repeatedly ruled that
22 a utility cannot recover the cost of financially-based incentive
23 compensation because financial measures are of more immediate
24 benefit to shareholders and financial measures are not necessary or
25 reasonable to provide utility services.³⁷ (Emphasis added).

³⁶ See Final Order in Docket 08-12002 at paragraph 549.

³⁷ *Application of Entergy Texas, Inc. for Rate Case Expenses Pertaining to PUC Docket No. 39896*, Docket No. 40295, Order at p. 2 (May 21, 2013). In that Order, p.2, note 6, the Texas PUC cited the following prior decisions: *Application of AEP Texas Central Company for Authority to Change Rates*, Docket No. 28840, Proposal for Decision at 92-97, Findings of Fact Nos. 164-170, Order at 35 (Aug. 15, 2005); *Application of AEP Texas Central Company for Authority to Change Rates*, Docket No. 33309, Proposal for Decision at 116-121, Finding of Fact No. 82, Order on Rehearing at 12 (March 4, 2008); *Application of Oncor Electric Delivery Company, LLC, for Authority to Change Rates*, Docket No. 35717, Proposal for Decision at 96-100, Finding of Fact No. 93, Order on Rehearing at 22 (Nov. 30, 2009); and *Application of CenterPoint Electric Delivery Company, LLC, for Authority to Change Rates*, Docket No. 38339, Proposal for Decision at 66-67, Findings of Fact Nos. 81-83, Order on Rehearing at 22 (June 23, 2011).

1 **Q: DID THE COMMISSION ALLOW RECOVERY OF LONG-TERM RSUS IN**
2 **SWEPCO'S LAST RATE CASE?**

3 A: Yes. In SWEPCO's last rate case, PUC Docket No. 46449, the Commission disallowed
4 recovery of SWEPCO's financially-based incentives, but allowed recovery of RSUs:

5 However, the \$359,705 of restricted stock units are not based on financial
6 performance measures as are other SWEPCO or AEP incentive plans and
7 are appropriate to include in SWEPCO's rates.³⁸

8 **Q: DO YOU AGREE WITH THE COMMISSION'S FINDING IN SWEPCO'S LAST**
9 **RATE CASE THAT PERFORMANCE UNITS ARE FINANCIALLY-BASED,**
10 **BUT ITS LONG-TERM RESTRICTED STOCK UNITS ARE NOT**
11 **FINANCIALLY-BASED?**

12 A: No. Employee payments made in stock are financial-based per se, especially those
13 awards that vest over time, since they are specifically designed to align the interests of
14 the employee with the financial interests of the company. Virtually all commissions agree
15 with this proposition, and as such, the Commission's decision to allow recovery of
16 financially-based RSU costs is incongruent with its other long-standing policies for the
17 treatment of financially-based incentives.

18 **Q: WHAT IS THE RATE-MAKING TREATMENT OF LONG-TERM INCENTIVE**
19 **COMPENSATION OF SWEPCO'S AFFILIATE COMPANY AEP/PSO IN**
20 **OKLAHOMA?**

21 A: The Oklahoma Corporation Commission ("OCC") disallows 100% of PSO's long-term
22 executive incentive plan costs, including RSUs. In PSO's 2006, 2008, 2015 and 2017
23 rate cases, the OCC found that AEP's long-term stock-based incentives should be
24 disallowed.³⁹ PSO's current long-term incentive plan is the same as SWEPCO's plan
25 and provides awards in the form of *performance units* and *restricted stock units* (RSUs).
26 In PSO's 2017 rate case, PUD 201700151, the OCC continued its regulatory treatment of
27 disallowing 100% of the utility's long-term incentive costs:

³⁸ Final Order in Docket No. 46449 at paragraph 199.

³⁹ See OCC Final Order in Cause No. PUD 200600285 at page 145; and OCC Order No. 564437 in Cause No. PUD 200800144 at page 21.

1 The long-term incentives are provided to highly compensated
2 employees to align their interests and loyalty to shareholders.
3 (Garrett Rev. Req. Resp. Test. at 40:15-41:3.) These costs are not
4 essential to serve the ratepayer and should be excluded from rate
5 recovery. The performance measures used in the long-term
6 incentive program are based on achieving financial goals that
7 benefit shareholders and thus should not be borne by ratepayers. It
8 would be inappropriate to require ratepayers to bear the costs of
9 incentive plans designed to encourage employees to put the
10 interests of shareholders first.⁴⁰

11 **Q: HOW IS LONG-TERM INCENTIVE COMPENSATION TREATED IN OTHER**
12 **STATES?**

13 A: The results of the Garrett Group Incentive Compensation Survey, discussed in the
14 previous section of this testimony, show that most states follow the general rule that
15 incentive pay associated with financial performance is not allowed in rates. This means
16 that long-term, stock-based incentives (including RSUs) are not allowed in most states.
17 According to the survey, 20 of the 24 western states tend to exclude all or virtually all
18 long-term stock-based incentive pay, either through an outright ban on stock-based
19 incentives or through applying the *financial performance* rule, which has the effect of
20 excluding long-term earnings-based and stock-based awards. These states include
21 Arizona, Arkansas, California, Colorado, Hawaii, Idaho, Kansas, Louisiana, Minnesota,
22 Missouri, Nevada, New Mexico, North Dakota, Oklahoma, Oregon, South Dakota, Utah,
23 Washington and Wyoming. In the other four states, Alaska, Iowa, Montana and
24 Nebraska, the issue just has not been addressed. Only Texas allows a portion of the long-
25 term stock incentives in rates through AEP's RSU program. I would encourage the
26 Commission to re-examine its position on the RSU issue.

⁴⁰ See Final Order in Cause No. PUD 201700151 at p. 24.

1 **Q: WHAT IS THE IMPACT OF YOUR ADJUSTMENT TO EXCLUDE THE**
2 **COMPANY'S LONG-TERM STOCK INCENTIVE PLAN COSTS.**

3 A: My adjustment removes 100% of the long-term incentive plan costs included in pro forma
4 operating expense in the amount of \$1,025,993, or \$371,024 to the Texas retail
5 jurisdiction. The calculations supporting this adjustment are set forth at Exhibit MG-2.5.

C. OTHER POST-EMPLOYMENT BENEFITS ("OPEB")

6 **Q: PLEASE DISCUSS THE COMPANY'S ADJUSTMENT TO RETIREMENT**
7 **PLAN EXPENSES.**

8 A: SWEPCO made three adjustments for its retirement plan expenses based on the 2020
9 actuarial reports. These adjustments increase total Company expenses by \$2,920,859. The
10 first adjustment (Adjustment A-3.10) addresses pension expense and increases those costs
11 by \$2,649,813. The second adjustment (Adjustment A-3.11) is for other post-retirement
12 benefits and increases expenses by \$546,861. The third adjustment (Adjustment A-3.12)
13 addresses post-employment benefits and reduces test year expenses by \$275,815.⁴¹

14 **Q: DO YOU AGREE WITH THE COMPANY'S ADJUSTMENTS TO THESE**
15 **RETIREMENT BENEFITS?**

16 A: Not entirely. I identified a problem with one of the adjustments. The adjustment to other
17 post-retirement benefits (Adjustment A-3.11) inadvertently referenced the wrong cell on
18 Schedule G-2.2,⁴² which resulted in the year 2020 being included as the updated pension
19 cost. The formula on the Adjustment A-3.11 work paper should have referenced the total
20 2020 cost, which is a negative \$7,753,163.⁴³ The 2020 expense amount found on
21 Schedule G-2.2 is a negative \$5,404,894.⁴⁴

⁴¹ Direct Testimony of Michael A. Baird, p. 25, line 14 – p. 26, line 2.

⁴² See the formula in WP A-3. 11 (OPEBS SFAS 106).xlsx, tab WP a 3.11, cell F13.

⁴³ See G-2.2 Attachment 1 (PBOP Expense).xlsx, tab PBOP, cell F14.

⁴⁴ See G-2.2 Attachment 1 (PBOP Expense).xlsx, tab PBOP, cell F17.

1 **Q: WHAT IS THE AMOUNT OF THE ADJUSTMENT TO CORRECT THIS**
2 **ERROR?**

3 A: Correcting this error so that the other post-retirement benefits expenses are based on the
4 2020 actuarial report reduces the total Company expenses by \$5,406,303, or \$2,117,108
5 for the Texas retail jurisdiction. The adjustment is found on Exhibit MG-2.6 attached to
6 my testimony.

D. PAYROLL EXPENSE

7 **Q: PLEASE DISCUSS THE COMPANY'S PAYROLL ANNUALIZATION**
8 **ADJUSTMENT.**

9 A: SWEPCO annualized its March 31, 2020 base payroll and then added a 3.5% increase
10 which resulted in an increase to payroll expense of \$2,143,713.⁴⁵ However, the
11 Company's work paper (WP A-3.1) does not contain the calculation of the annualized
12 amounts but does list percentages to the side of the individual annualized payroll amounts
13 that range from zero to three percent.⁴⁶

14 **Q: DO YOU AGREE WITH THE COMPANY'S APPROACH?**

15 A: No. Regarding the first part of the adjustment, an annualization factor that multiplies a
16 final pay period by 12 for weekly or 26 for biweekly payments is appropriate, to the extent
17 the final pay period is representative of ongoing levels. Regarding the second part of the
18 adjustment, however, an additional increase for pay raises based on the nominal pay
19 increase rate is almost never appropriate because payroll levels typically do not actually
20 increase by the amount of the nominal increase. In other words, a 3.5% pay raise will
21 almost never result in a 3.5% increase in payroll expense levels.

22 The actual increase amount associated with a nominal pay raise is not known and
23 measurable because too many other factors impact the overall change in payroll expense.
24 These factors include: (1) the normal turnover of employees that occurs when employees
25 come onto and leave the payroll registers on a regular basis, with retiring employees

⁴⁵ Direct Testimony of Michael A. Baird, p. 21, lines 2-12.

⁴⁶ See WP A-3.1 (Payroll adjustment).xlsx, tab Att 1 base rates, columns F and K.

1 taking higher salaries levels off the system and new employees coming on at lower pay
2 scale levels; (2) workforce reorganizations, where significant reductions in the workforce
3 levels are achieved through new technologies or other innovations; (3) productivity gains,
4 where smaller reductions in the workforce levels are achieved on an ongoing basis
5 through increased employee efficiencies; and (4) capitalization ratio changes, where more
6 payroll costs are capitalized (rather than expensed) during a period of capital expansion
7 – such as SWEPCO is experiencing now.⁴⁷ All of these factors impact overall payroll
8 cost levels as much or more than pay raises do. Yet, regulated utilities in rate cases, often
9 only acknowledge the pay raise impacts, while ignoring the impacts of these other
10 important changes.

11 **Q: HOW SHOULD TEST YEAR PAYROLL LEVELS BE ADJUSTED?**

12 A: When rates are based on an historical test year, as they are in Texas, payroll expense
13 should be annualized – provided the period annualized is representative of ongoing levels
14 – and the inquiry should end there. It is not appropriate to adhere to a test year cut-off
15 for rate base investment, cost of capital, depreciation expense, taxes and revenues, but
16 then go beyond the test year for payroll expense, especially when it is done in a piecemeal
17 fashion that looks only at pay raises, without including basic offsetting adjustments for
18 productivity improvements and turnover.

19 **Q: WHAT PROCEDURES DID YOU APPLY TO DETERMINE IF THE**
20 **COMPANY'S ANNUALIZED AMOUNTS ARE REPRESENTATIVE FOR THE**
21 **COMPANY'S COSTS?**

22 A: I requested the payroll by pay period for the test year and the post-test year period.⁴⁸ The
23 data provided by the Company showed that the SWEPCO's payroll costs declined during
24 test year which the Company then offset with post-test year pay increases.

⁴⁷ As utilities add plant, a portion of the payroll costs are capitalized into the cost of the new plant. The rest of the payroll costs are expensed and that expense level is what we use to set rates. If a utility is in a capital expansion phase, its capitalization ratio will generally increase. This will make expense levels go down, even if overall payroll costs are going up. Thus, a 3% increase in the capitalization ratio alone can offset a nominal 3% pay raise.

⁴⁸ See SWEPCO's responses to CARD 4-5 Attachment 1, CARD 5-5 Attachment 1, and CARD 8-1 Attachment 1.

1 **Q: WHAT WOULD CAUSE THIS DECLINE IN PAYROLL COSTS?**

2 A: SWEPCO has reduced their employee levels during the test year. At the beginning of the
3 test year SWEPCO had 1,468 employees. At the end of the test year SWEPCO only had
4 1,459 employees.⁴⁹ By December 2020 SWEPCO reported having only 1,452
5 employees.⁵⁰

6 **Q: WHAT CAUSED THIS DECLINE IN EMPLOYEE LEVELS?**

7 A: The Company reports that they offered a retirement incentive to its employees but stated
8 that only one SWEPCO employee accepted the retirement incentive package.⁵¹ It appears
9 that most of the employee decline was the result of attrition.

10 **Q: YOU STATED THAT THE SWEPCO PAYROLL COSTS DECLINED DURING**
11 **THE TEST YEAR. DID THE DECLINE CONTINUE DURING THE POST-TEST**
12 **YEAR PERIOD?**

13 A: The decline continued only through the second quarter, but after the October 1, 2020 pay
14 increases took effect, the payroll cost increased slightly above the test year level. The
15 annualized base pay for the post-test year pay periods from October through December
16 2020 was 0.87% more than the base pay for the test year.⁵²

17 **Q: WHAT PAYROLL ANNUALIZATION ADJUSTMENT DO YOU RECOMMEND**
18 **BASED ON YOUR REVIEW OF SWEPCO'S PAYROLL COSTS?**

19 A: I recommend that SWEPCO's payroll expenses be set at 0.87% above the test year level
20 to reflect all changes from the test year and not only the post-test year pay increases. The
21 adjustment reduces SWEPCO's proposed payroll increase by \$1,496,365 total Company,
22 or \$585,976 for the Texas retail jurisdiction, as set forth in Exhibit MG-2.1.

⁴⁹ See CARD 4-5, Attachment 1.

⁵⁰ See CARD 5-5, Attachment 1.

⁵¹ See Staff 5-24.

⁵² See CARD SWEPCO PR WP from CARD 4-5, CARD 5-5, and CARD 8-1, Attachments 1.xlsx, cell C87.

1 **Q: DOES THIS ADJUSTMENT AFFECT SWEPCO'S PAYROLL TAX EXPENSE?**

2 A: Yes. This adjustment reduces the Texas retail jurisdictional payroll tax expense by
3 \$37,885. This adjustment is also shown in Exhibit MG-2.1.

4 **Q: DID THE RETIREMENT INCENTIVE OFFER AFFECT THE AEPSC**
5 **PAYROLL?**

6 A: Yes. The Company reported that 189 employees of AEPSC accepted the retirement
7 incentive package.

8 **Q: DID SWEPCO INCLUDE SAVINGS FROM THE RETIREMENT INCENTIVE**
9 **PACKAGE IN THE REVENUE REQUIREMENT?**

10 A: No. Instead, SWEPCO increased the allocated AEPSC payroll costs by \$3.8 million, or
11 9.8% above test year levels. This increase fails to properly account for the savings
12 generated by the early retirement package.

13 **Q: DID YOU REVIEW AEPSC'S POST-TEST YEAR PAYROLL COSTS TO**
14 **DETERMINE THE EXTENT OF PAYROLL COST SAVINGS THAT**
15 **RESULTED FROM THE RETIREMENT INCENTIVE OFFERING?**

16 A: Yes. I reviewed the post-test year payroll costs of AEPSC and found that the AEPSC
17 post-test year payroll costs were comparable to the test year, increasing only 0.24%.⁵³

18 **Q: WHAT ADJUSTMENT DO YOU RECOMMEND FOR THE AEPSC PAYROLL**
19 **COST?**

20 A: I recommend the AEPSC payroll expenses be set at the test year level to reflect the
21 reduction in employee levels that offset almost all increases that also may have occurred
22 in the post-test year period. This adjustment reverses SWEPCO's proposed AEPSC
23 payroll increase of \$3,804,876 total Company, or \$1,489,989 for the Texas retail
24 jurisdiction. This adjustment is found on Exhibit MG-2.2.

⁵³ See CARD AEPSC PR WP from CARD 5-2, Attachment 1.xlsx, cell C28.

1 **V. OTHER OPERATING EXPENSE ADJUSTMENTS**

2 **A. SELF-INSURANCE EXPENSE**

3 **Q: PLEASE DISCUSS THE SELF-INSURANCE RESERVE REQUESTED BY THE**
4 **COMPANY.**

5 A: SWEPCO is requesting the approval of a self-insurance reserve under 16 Tex. Admin.
6 Code § 25.231(b)(1)(G). Mr. Gregory S. Wilson provides testimony supporting an annual
7 accrual of \$1,689,700 which consists of \$799,700 for average annual transmission and
8 distribution property losses of at least \$500,000 and \$890,000 to achieve a reserve of
9 \$3,560,000 within four years.⁵⁴

10 **Q: WHAT ARE THE REQUIREMENTS UNDER 16 TEX. ADMIN. CODE §**
11 **25.231(B)(1)(G) FOR THE ESTABLISHMENT OF A SELF-INSURANCE**
12 **RESERVE?**

13 A: 16 Tex. Admin. Code § 25.231(b)(1)(G) states:

14 Accruals credited to reserve accounts for self-insurance under a plan
15 requested by an electric utility and approved by the commission. The
16 commission shall consider approval of a self-insurance plan in a rate case
17 in which expenses or rate base treatment are requested for a such a plan.
18 For the purposes of this section, a self-insurance plan is a plan providing
19 for accruals to be credited to reserve accounts. The reserve accounts are to
20 be charged with property and liability losses which occur, and which could
21 not have been reasonably anticipated and included in operating and
22 maintenance expenses, and are not paid or reimbursed by commercial
23 insurance. The commission will approve a self-insurance plan to the
24 extent it finds it to be in the public interest. In order to establish that the
25 plan is in the public interest, the electric utility must present a cost benefit
26 analysis performed by a qualified independent insurance consultant who
27 demonstrates that, with consideration of all costs, self-insurance is a
28 lower-cost alternative than commercial insurance and the ratepayers will
29 receive the benefits of the self-insurance plan. The cost benefit analysis
30 shall present a detailed analysis of the appropriate limits of self-insurance,
31 an analysis of the appropriate annual accruals to build a reserve account

⁵⁴ See Direct Testimony of Gregory S. Wilson, p. 4, lines 16-21.

1 for self-insurance, and the level at which further accruals should be
2 decreased or terminated.⁵⁵

3 The primary requirement for the Commission to approve the self-insurance plan is a
4 finding that it is in the public interest based on a cost benefit study that shows that it is a
5 lower cost alternative to commercial insurance.

6 **Q: HAS THE COMPANY MET THE REQUIREMENTS OF 16 TEX. ADMIN. CODE**
7 **§ 25.231(B)(1)(G) BY SHOWING THE PROPOSED ACCRUAL OF \$1,689,700 IS**
8 **LESS THAN THE COST OF COMMERCIAL INSURANCE?**

9 A: No. Mr. Wilson argued that the self-insurance plan would cost less than commercial
10 insurance because commercial insurance would have to provide for additional costs such
11 as commissions and profits of the insurance company.⁵⁶ However, Mr. Wilson did not
12 provide any empirical evidence in support his cost benefit analysis. For example, he did
13 not demonstrate by means of actual data that shows that self-insurance is a lower-cost
14 alternative than commercial insurance and the ratepayers will receive the benefits of the
15 self-insurance plan. Wilson presented no commercial insurance cost to compare with his
16 calculated cost of self-insurance. As a result, it is impossible to conclude that the self-
17 insurance cost he calculated is less than commercial insurance without the commercial
18 insurance cost for comparison. Moreover, even if self-insurance was hypothetically less
19 costly than commercial insurance, the establishment of a reserve in only four years more
20 than doubles the self-insurance cost levels. This means that the period for the recovery
21 of a reserve from ratepayers would likely have to be extended by several years for self-
22 insurance to be lower than the cost of commercial insurance.

23 It is important to note that an appropriate cost benefit study and analysis required by the
24 regulations for self-insurance approval would have to have been presented in direct
25 testimony. The Company cannot come back in rebuttal testimony and attempt to present
26 this essential information when other parties to the case would have no opportunity to
27 evaluate and respond to this new information.

⁵⁵ See 16 Tex. Admin. Code § 25.231(b)(1)(G). (Emphasis added).

⁵⁶ Direct Testimony of Gregory S. Wilson, p. 11, lines 1-3.

1 Q: WHAT IS YOUR RECOMMENDATION REGARDING SWEPCO'S REQUEST
2 TO ESTABLISH AN INSURANCE RESERVE?

3 A: I recommend that the request be denied at this time. If, in its next rate case, SWEPCO
4 provides a self-insurance proposal that is below the cost of alternatives such as
5 commercial insurance and supports that comparison with documentary evidence that it
6 indeed is the lowest cost alternative, then that proposal could be evaluated at that time.

7 Q: HOW WAS THE COMPANY'S ADJUSTMENT CALCULATED?

8 A: Mr. Wilson calculated expected average annual losses of \$799,700, and then more than
9 doubles that amount to \$1,689,700 to establish the reserve of \$3,560,000 within four
10 years.

11 Q: WHAT ADJUSTMENT DO YOU RECOMMEND FOR THE SELF-INSURANCE
12 EXPENSE?

13 A: I recommend that the Company's requested increase in property insurance of \$1,689,700
14 be reversed. This adjustment is found on Exhibit MG-2.8.

15 B. VEGETATION MANAGEMENT

16 Q: PLEASE DESCRIBE SWEPCO'S REQUEST FOR ADDITIONAL
17 VEGETATION MANAGEMENT EXPENSE IN THIS CASE.

18 A: In the test year, SWEPCO incurred \$9.57 million for vegetation management expenses.⁵⁷
19 This closely approximates the \$9.93 million authorized for vegetation management in the
20 Company's last rate case, Docket No. 46449, which included a \$2 million increase over
21 the 2016 test year level in that docket.⁵⁸ In this case, SWEPCO has requested an
22 additional \$5 million above the test year levels for vegetation management expenses, for
23 a total Texas retail jurisdictional expense level of \$14.57 million.⁵⁹ SWEPCO claims the
24 \$14.57 million it is requesting is only 38% of the amount needed to implement a four-

⁵⁷ Direct Testimony of Drew W. Seidel, 18:11 – 19:1.

⁵⁸ *Id.*, at p. 16, line 22 – p. 17, line 2.

⁵⁹ *Id.*, at p.18, line 10 – p. 19, line 1.

1 year vegetation management cycle which would cover all of SWEPCO's Texas
2 distribution system within four years.⁶⁰

3 **Q: HAS SWEPCO IMPROVED ITS RELIABILITY MEASURES SINCE THE**
4 **COMMISSION APPROVED AN INCREASED LEVEL OF SPENDING IN THE**
5 **2016 RATE CASE?**

6 A: No. SWEPCO reported a SAIFI of 1.73 for 2016 and 1.79 for the test year.⁶¹ This is not
7 a meaningful improvement.

8 **Q: DID SWEPCO INCREASE ITS VEGETATION MANAGEMENT SPENDING TO**
9 **THE \$9.93 MILLION LEVEL APPROVED IN ITS LAST RATE CASE?**

10 A: Yes. SWEPCO did increase its spending on vegetation management above that level in
11 2018, but elected to spend significantly less in 2017. SWEPCO reports the following
12 amounts for vegetation management expenses in Texas:⁶²

Year	Amount
2017	\$6,025,129
2018	\$12,954,922
2019	\$9,359,676
Test Year Actual	\$9,568,282
Requested Amount	\$14,570,000

13 **Q: IS SWEPCO REQUIRED TO SPEND THE AMOUNT AUTHORIZED IN A RATE**
14 **CASE FOR VEGETATION MANAGEMENT?**

15 A: No. SWEPCO is not required to spend the amount it authorized for vegetation
16 management expense in a rate case. However, when a utility indicates that a certain
17 expenditure level is necessary, but it does not follow through on spending at that level as
18 the Company did in 2017, it does raise questions as to whether that cost level is essential.

⁶⁰ *Id.*, at p.19, lines 1–4.

⁶¹ *Id.*, at p.10, lines 10–12.

⁶² See the CARD 2-14, Attachment 1.

1 **Q: IS SWEPCO PROHIBITED FROM SPENDING MORE ON A SPECIFIED**
2 **EXPENSE THAN WAS INCLUDED IN A RATE CASE?**

3 A: No. In fact, a public utility is required to spend more than the level approved in a rate
4 case, if a higher level of spending is necessary to provide safe and reliable service to
5 customers.

6 **Q: WHAT IS YOUR RECOMMENDATION REGARDING SWEPCO'S REQUEST**
7 **FOR AN ADDITIONAL \$5 MILLION DOLLARS FOR VEGETATION**
8 **MANAGEMENT FOR THE TEXAS DISTRIBUTION SYSTEM?**

9 A: Based on the information the Company presented SWEPCO's actual spending levels have
10 remained close to the \$9.93 million authorized for vegetation management in the
11 Company's last rate case, Docket No. 46449. Therefore, I recommend that the
12 Company's request for a \$5 million increase above test year levels be denied, and that
13 SWEPCO's reliability continue to be monitored.

14 **Q: WHAT IS THE AMOUNT OF THE ADJUSTMENT THAT YOU RECOMMEND?**

15 A: I recommend that SWEPCO's requested level of vegetation management expenses for
16 Texas be reduced by \$5,000,000. This adjustment is found on Exhibit MG-2.7.

17 **VI. CONCLUSION**

18 **Q: WHAT IS THE OVERALL IMPACT OF YOUR RECOMMENDATIONS ON**
19 **THE COMPANY'S REVENUE REQUIREMENTS?**

20 A: The overall impact of the adjustments I recommend in my testimony on SWEPCO's
21 requested revenue requirement is a reduction of \$27,842,451 as set forth in Table 1 in
22 Section II of this testimony and also in Exhibit MG-2.

23 **Q: DO YOU HAVE ANY FURTHER COMMENTS?**

24 A: Yes. My recommendations address only a few issues affecting SWEPCO's revenue
25 requirement. The fact that I do not express an opinion on a particular issue is not to be
26 interpreted as agreement with the Company's position on that issue. The
27 recommendations in this testimony should be considered in conjunction with the

1 recommendations of the other CARD witnesses and the witnesses of other intervening
2 parties to this case.

3 **Q: DOES THIS CONCLUDE YOUR TESTIMONY AT THIS TIME?**

4 A: Yes, it does.

SOAH DOCKET NO. 473-21-0538

PUC DOCKET NO. 51415

**APPLICATION OF SOUTHWESTERN § BEFORE THE STATE OFFICE
ELECTRIC POWER COMPANY FOR § OF
AUTHORITY TO CHANGE RATES § ADMINISTRATIVE HEARINGS**

DIRECT TESTIMONY AND EXHIBITS

OF MARK E. GARRETT

EXHIBIT MG-1:

QUALIFICATIONS

MARK E. GARRETT

CONTACT INFORMATION:

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Edmond, OK 73013
(405) 239-2226

EDUCATION:

Juris Doctor Degree, With Honors, Oklahoma City University Law School, 1997
Post Graduate Hours in Accounting, Finance and Economics, 1984-85:
University of Texas at Arlington; University of Texas at Pan American;
Stephen F. Austin State University
Bachelor of Arts Degree, University of Oklahoma, 1978

CREDENTIALS:

Member Oklahoma Bar Association, 1997, License No. 017629
Certified Public Accountant in Oklahoma, 1992, Certificate No. 11707-R
Certified Public Accountant in Texas, 1986, Certificate No. 48514

WORK HISTORY:

GARRETT GROUP CONSULTING, INC. – Regulatory Consulting Practice (1996 - Present)

Participates as a consultant and expert witness in gas and electric regulatory proceedings and other matters before regulatory agencies in rate case proceedings to determine just and reasonable rates. Reviews management decisions of regulated utilities regarding the reasonableness of prices paid for electric plant, gas plant, purchased power, renewable energy projects, natural gas supplies and transportation, and coal supplies and transportation. Participates in legislative advisory role regarding regulated utilities. Participates as an Instructor at NMSU Center for Public Utilities and as a Speaker at NARUC Staff Subcommittee on Accounting and Finance.

OKLAHOMA CORPORATION COMMISSION - Coordinator of Accounting and Financial

Analysis (1991 - 1994) Planned and supervised the audits of major public utility companies doing business Oklahoma for the purpose of determining revenue requirements. Presented both oral and written testimony as an expert witness for Staff in defense of numerous accounting and financial recommendations related to cost-of-service based rates. Audit work and testimony covered all areas of rate base and operating expense. Supervised, trained and reviewed the audit work of numerous Staff CPAs and auditors. Promoted from Supervisor of Audits to Coordinator in 1992.

FREEDOM FINANCIAL CORPORATION - Controller (1987 - 1990)

Responsible for all financial reporting including monthly and annual financial statements, cash flow statements, budget reports, long-term financial planning, tax planning and personnel development. Managed the General Ledger and Accounts Payable departments and supervised a staff of seven CPAs and accountants. Reviewed all subsidiary state and federal tax returns and facilitated the annual independent financial audit and all state or federal tax audits. Received promotion from Assistant Controller in September 1988.

SHELBY, RUCKSDASHEL & JONES, CPAs - Auditor (1986 - 1987)

Audited the financial statements of businesses in the state of Texas, with an emphasis in financial institutions.

Previous Experience Related to Cost-of-Service, Rate Design, Pricing and Energy-Related Issues

1. **Oklahoma Gas & Electric Co., 2020 (Arkansas) (Docket No. 18-046-FR)** – Participating as an expert witness on behalf of the Arkansas River Valley Energy Consumers (“ARVEC”)¹ before the Arkansas Public Service Commission in OG&E’s Formula Rate Plan application to provide testimony on cost of service issues.
2. **El Paso Electric Company, 2020 (Texas), (Docket No. 51348)** – Participating as an expert witness on behalf of the City of El Paso in the El Paso Electric Company annual Distribution Cost Recovery Factor (“DCRF”) application to provide recommendations to the Texas Public Utility Commission regarding the Company’s requested DCFR increase.
3. **V Energy, 2020 (Nevada), (Docket No. 20-07023)** – Participating as an expert witness on behalf of the Southern Nevada Gaming Group (“SNGG”) before the Nevada PUC. Sponsoring written and oral testimony in the Nevada Power and Sierra Pacific Joint Integrated Resource Plan (“IRP”) to provide analysis of the proposed transmission additions and cost allocations.
4. **Southwestern Electric Power Company, 2020 (Texas), (PUC Docket No. 51415)** – Participating as an expert witness on behalf of Cities Advocating Reasonable Deregulation (“CARD Cities”) before the Texas Public Utility Commission in SWEPCO’s general rate case application to provide testimony on various revenue requirement issues.
5. **Dominion Energy South Carolina, 2020 (South Carolina), (Docket No. 2020-125-E)** – Participating as an expert witness on behalf of DOD/FEA in DESC’s rate case application, sponsoring testimony to address various revenue requirement, rate design and tax issues.
6. **Cascade Natural Gas, 2020 (Washington), (NG-UG-200568)** – Participating as an expert witness on behalf of Public Counsel in Cascade’s rate case application, sponsoring testimony to address various revenue requirement and tax issues.
7. **Nevada Power Company, 2020 (Nevada) (Docket No. 20-06003)** – Participating as an expert witness on behalf of Bureau of Consumer Protection (“BCP”) before the Nevada Public Utility Commission to address various revenue requirement issues in the case.
8. **El Paso Electric Company, 2020 (New Mexico), (Docket RC-20-00104-UT)** – Participating as an expert witness on behalf of the City of Las Cruces and Dona Ana county in EPE’s rate case application, sponsoring testimony to address various revenue requirement and tax issues.
9. **Oklahoma Gas and Electric Company, 2020 (Oklahoma), (Cause No. PUD 202000021)** – Participating as an expert witness on behalf of Oklahoma Industrial Energy Consumers (“OIEC”) before the Oklahoma Corporation Commission in OG&E’s Grid Enhancement Plan application. Sponsoring testimony to address the utility’s proposed cost recovery mechanism and cost of service allocations.
10. **Philadelphia Gas Works, 2020 (Pennsylvania), (Docket No. R-2020-3017206)** – Participating expert witness on behalf of Office of Consumer Advocate (“OCA”) before the Pennsylvania Public Utility Commission to address various revenue requirement issues in PGW’s rate case.

¹ ARVEC is an association of industrial manufacturing facilities in northwest Arkansas.

11. **Atmos MidTex (Texas), 2020 (Texas), (Dallas Annual Rate Review)** – Participating as an expert witness on behalf of the City of Dallas before the Texas Railroad Commission in Atmos’s Dallas Annual Rate Review (“DARR”) proceeding. Sponsoring recommendations on various revenue requirement issues.
12. **Southwest Gas Corporation, 2020 (Nevada) (Docket No. 20-02023)** – Participated as an expert witness on behalf of Bureau of Consumer Protection (“BCP”) before the Nevada Public Utility Commission to address various revenue requirement issues.
13. **El Paso Electric Company, 2019 (Texas), (Docket No. 49849)** – Participating as an expert witness on behalf of the City of El Paso in the merger of El Paso Electric Company with Sun Jupiter Holdings LLC and IIF US Holdings 2 LLP to provide recommendations to the Texas Public Utility Commission regarding the treatment of tax issues in the proposed merger agreement.
14. **Nevada Senate Bill 300 Rulemaking, 2019 (Nevada), (Docket No. 19-069008)** – Participating as an expert witness on behalf of the Southern Nevada Gaming Group before the Nevada PUC to assist with the development of alternative ratemaking regulations under SB 300.
15. **Entergy Arkansas, 2019 (Arkansas), (Docket No. 19-020-TF)** – Participating as an expert witness on behalf of the Arkansas industrial consumer group to review EAI’s application to allocate its perceived under-recovery of off-system sales margins to Arkansas customers.
16. **Public Service Company of Oklahoma, 2019 (Oklahoma) (Cause No. PUD 201900201)** – Participating as an expert witness on behalf of OIEC before the OCC in AEP/PSO’s application for approval for the cost recovery of selected wind facilities.
17. **Oklahoma Gas & Electric Co., 2019 (Arkansas) (Docket No. 18-046-FR)** – Participating as an expert witness on behalf of the Arkansas River Valley Energy Consumers (“ARVEC”)² before the Arkansas Public Service Commission in OG&E’s Formula Rate Plan application to provide testimony on various revenue requirement, cost of service and rate design issues.
18. **Southwestern Public Service Co., (“SPS”) 2019 (Texas), (Docket No. 49831)** – Participating as an expert witness on behalf of the Alliance of Xcel Municipalities (“AXM”) in the SPS general rate case application to provide testimony before the Texas Public Utility Commission regarding rate base and operating expense issues and sponsor the AXM Accounting Exhibits.
19. **Southwestern Electric Power Company, 2019 (Arkansas), (Docket No. 19-008-U)** – Participated as an expert witness on behalf of Western Arkansas Large Energy Consumers (“WALEC”) before the Arkansas Public Service Commission in SWEPSCO’s rate case to address various revenue requirement and rate design issues.
20. **Anchorage Municipal Light and Power and Chugach Electric Association, 2019 (Alaska), (Docket No. U-19-020)** – Participating as an expert witness before the Regulatory Commission of Alaska on behalf of Providence Health and Services to provide testimony on pending acquisition of ML&P by Chugach to address the proposed acquisition premium and other issues associated with the public interest.

² ARVEC is an association of industrial manufacturing facilities in northwest Arkansas.

21. **Sierra Pacific Power Company, 2019 (Nevada), (Docket No. 19-06002)** – Participated as an expert witness on behalf of Bureau of Consumer Protection (“BCP”) before the Nevada Public Utility Commission to address various revenue requirement issues.
22. **Air Liquide Hydrogen Energy U.S., 2019 (Nevada), (704B Exit Application, Docket No. 19-02002)** – Participated as an expert witness on behalf of Air Liquide before the Nevada PUC. Sponsoring written and oral testimony in Air Liquide’s application to purchase energy and capacity from a provider other than NV Energy.
23. **Empire District Electric Company, 2019 (Oklahoma), (Cause No. PUD 201800133)** – Participated as an expert witness on behalf of Oklahoma Industrial Energy Consumers (“OIEC”) before the Oklahoma Corporation Commission in Empire’s general rate case to address various revenue requirement, rate design and tax issues.
24. **Indiana Michigan Power, 2019 (Indiana), (Docket No. 45235)** – Participating as an expert witness on behalf of the Office of Utility Consumer Counselor in I&M’s rate case application, sponsoring testimony to address various revenue requirement and tax issues.
25. **Puget Sound Energy, 2019 (Washington), (Docket No. 190529-30)** – Participating as an expert witness on behalf of Public Counsel in PSE’s rate case application, sponsoring testimony to address various revenue requirement and tax issues.
26. **Anchorage Municipal Light and Power, 2019 (Alaska), (Docket No. U-18-102)** – Participating as an expert witness before the Regulatory Commission of Alaska on behalf of Providence Health and Services to provide testimony on the ratemaking treatment of ML&P’s acquired interest in the Beluga River Unit gas field with ratepayer funds.
27. **Oklahoma Gas and Electric Company, 2019 (Oklahoma), (Cause No. PUD 201800140)** – Participated as an expert witness on behalf of Oklahoma Industrial Energy Consumers (“OIEC”) before the Oklahoma Corporation Commission in OG&E’s General Rate Case application. Sponsoring testimony to address the utility’s overall revenue requirement and rate design proposals.
28. **Cascade Natural Gas, 2019 (Washington) (Docket No. 190210)** – Participated as an expert witness on behalf of Public Counsel in Cascade’s rate case application. Sponsoring testimony to address various revenue requirement and tax issues.
29. **CenterPoint Energy Houston Electric, 2019 (Texas) (Docket No. 49421)** – Participated as an expert witness on behalf of City of Houston before the Public Utility Commission of Texas in CenterPoint Energy’s rate case application to provide testimony on various revenue requirement issues.
30. **Oklahoma Gas & Electric Co., 2018 (Arkansas) (Docket No. 18-046-FR)** – Participated as an expert witness on behalf of the Arkansas River Valley Energy Consumers (“ARVEC”)³ before the Arkansas Public Service Commission in OG&E’s Formula Rate Plan application to provide testimony on various revenue requirement, cost of service and rate design issues.

³ ARVEC is an association of industrial manufacturing facilities in northwest Arkansas.

31. **Southwest Gas Corporation, 2018 (Nevada) (Docket No. 18-05031)** – Participated as an expert witness on behalf of Bureau of Consumer Protection (“BCP”) before the Nevada Public Utility Commission to address various revenue requirement issues.
32. **Puget Sound Energy, 2018 (Washington) (Docket No. UE 18089)** - Participated as an expert witness on behalf of Public Counsel in PSE’s Emergency Rate Relief proceeding. Sponsoring testimony to address the application itself and various revenue requirement and TCJA issues.
33. **Public Service Company of Oklahoma, 2018 (Oklahoma) (Cause No. PUD 201800097)** – Participated as an expert witness on behalf of OIEC before the OCC in AEP/PSO’s general rate case application to provide testimony on various revenue requirement, cost of service and rate design issues.
34. **Entergy Texas Inc., 2018 (Texas) (PUC Docket No. 48371)** – Participated as an expert witness on behalf of the Cities in ETI’s general rate case to provide testimony on various cost of service issues and on the utility’s overall revenue requirement.
35. **Atmos Energy Corp., Mid-Tex Division, 2018 (Texas) (Docket No. GUD No. 10779)** – Participated as an expert witness on behalf of the Atmos Texas Municipalities to review the utility’s requested revenue requirement including TCJA adjustments.
36. **CenterPoint Energy Houston Electric, LLC, 2018 (Texas) (Docket No. 48226)** – Participated as an expert witness on behalf of City of Houston before the Public Utility Commission of Texas in CenterPoint Energy’s application for approval to amend its distribution cost recovery factor (DCRF) to address the utility’s treatment of the Tax Cuts and Jobs Act of 2017 (“TCJA”).
37. **NV Energy, 2018 (Nevada) (Docket No. 17-10001)** – Participated as an expert witness on behalf of the Energy Choice Initiative (“ECI”) before the Governor’s Committee on Energy Choice, in an investigatory docket of an Issue of Public Importance Regarding the Pending Energy Choice Initiative and the Possible Restructuring of Nevada’s Energy Industry.
38. **Southwestern Electric Power Company, 2018 (Texas) (PUC Docket No. 48233)** – Participated as an expert witness on behalf of Cities Advocating Reasonable Deregulation (“CARD Cities”) before the Texas Public Utility Commission in SWEPCO’s application to implement base rate reductions as result of the Tax Cuts and Jobs Act of 2017 (“TCJA”).
39. **Oncor Electric Delivery Company (Texas), 2018 (PUC Docket No. 48325)** – Participated as an expert witness before the Texas Public Utility Commission in Oncor’s application for authority to decrease rates based on the Tax Cuts and Jobs Act of 2017 (“TCJA”).
40. **Public Service Company of Oklahoma (“PSO”) (Oklahoma), 2018 (Cause No. PUD 201800019)** – Participated as an expert witness on behalf of OIEC before the OCC in AEP/PSO’s application regarding ADIT under the Tax Cuts and Jobs Act of 2017 (“TCJA”).
41. **Oklahoma Natural Gas Company, 2018 (Cause No. PUD 201800028)** – Participated as an expert witness on behalf of the OIEC before the Oklahoma Corporation Commission in ONG’s Performance Based Rate Change Tariff, to address issues involving the impacts of the Tax Cuts and Jobs Act of 2017 (“TCJA”).

42. **Oklahoma Gas & Electric Co. (Arkansas), 2018 (Docket No. 18-006-U** – Participated as an expert on behalf of the Arkansas River Valley Energy Consumers (“ARVEC”) before the Arkansas Public Service Commission in the matter of an Investigation of the Effect on Revenue Requirements Resulting from Changes to Corporate Income Tax Rates under the Tax Cuts and Jobs Act of 2017 (“TCJA”).
43. **Texas Gas Service, 2018** – Participated as a consulting expert on behalf of the City of El Paso regarding implementation of rate changes related to the Tax Cuts and Jobs Act of 2017 (“TCJA”).
44. **Sierra Pacific Power Company (Nevada), 2018 (Docket No. 18-02011 and 18-02015)** – Participated as an expert witness on behalf of the Northern Nevada Utility Customers⁴ before the Nevada PUC in SPPC’s application related to the Tax Cuts and Jobs Act of 2017 (“TCJA”).
45. **Nevada Power Company (Nevada), 2018 (Docket No. 18-02010 and 18-02014)** – Participated as an expert witness on behalf of the Southern Nevada Gaming Group before the Nevada PUC in NPC’s application related to the Tax Cuts and Jobs Act of 2017 (“TCJA”).
46. **Public Service Company of Oklahoma (“PSO”) (Oklahoma), 2017 (Cause No. PUD 201700572)** – Participated as an expert witness on behalf of OIEC before the OCC in AEP/PSO’s application to examine the impacts of the Tax Cuts and Jobs Act of 2017 (“TCJA”).
47. **Empire District Electric Company (“EPE”) (Oklahoma), 2018 (Cause No. PUD 201700471)** – Participated as an expert witness on behalf of Oklahoma Industrial Energy Consumers (“OIEC”) before the Oklahoma Corporation Commission in Empire’s application to add 800MW of wind. Sponsoring testimony to address the various ratemaking and tax issues.
48. **Oklahoma Gas and Electric Company (“OG&E”), (Oklahoma), 2018 (Cause No. PUD 201700496)** – Participated as an expert witness on behalf of Oklahoma Industrial Energy Consumers (“OIEC”) before the Oklahoma Corporation Commission in OG&E’s General Rate Case application. Sponsoring testimony to address the utility’s overall revenue requirement and rate design proposals.
49. **Public Service Company of Oklahoma (“PSO”) (Oklahoma), 2017 (Cause No. PUD 201700276)** – Participated as an expert witness on behalf of OIEC before the OCC in AEP/PSO’s Wind Catcher case to provide testimony on various ratemaking and tax issues.
50. **Southwestern Public Service Co. (“SPS”) (Texas), 2017 (PUCT Docket No. 47527)** – Participating as an expert witness on behalf of the Alliance of Xcel Municipalities (“AXM”) in the SPS general rate case application to provide testimony before the Texas Public Utility Commission regarding rate base and operating expense issues and sponsor the AXM Accounting Exhibits.
51. **Southwestern Electric Power Company, (“SWEPCO”) (Texas), 2017 (PUC Docket No. 47461)** – Participated as an expert witness on behalf of Cities Advocating Reasonable Deregulation (“CARD Cities”) before the Texas Public Utility Commission in SWEPCO’s Wind Catcher case proceeding to provide testimony on various ratemaking and tax issues.

⁴ The Northern Nevada Utility Consumers is a group of large commercial and industrial customers in the SPPC service territory.

52. **Atmos MidTex (Texas), 2017 (Docket No. 10640)** – Participated as an expert witness on behalf of the City of Dallas before the Texas Railroad Commission in Atmos’s Dallas Annual Rate Review (“DARR”) proceeding. Sponsoring testimony on various revenue requirement issues.
53. **Avista Utilities (Washington), 2017 (Docket Nos. UE-170485/UG-170486)** – Participated as an expert witness on behalf of Public Counsel in Avista’s general rate case proceeding. Sponsoring testimony to address various revenue requirement issues and Avista’s requested attrition adjustments.
54. **Nevada Power Company (Nevada), 2017 (Docket No. 17-06003)** – Participated as an expert witness on behalf of the Southern Nevada Hotel Group before the Nevada PUC in NPC’s general rate case proceeding. Sponsoring testimony on various revenue requirement, depreciation, and rate design issues.
55. **Anchorage Municipal Light and Power (Alaska), 2017 (Docket No. U-17-008)** – Participating as an expert witness before the Regulatory Commission of Alaska on behalf of Providence Health and Services to provide testimony in ML&P’s General Rate Case on various revenue requirement and rate design issues.
56. **Public Service Company of Oklahoma (Oklahoma), 2017 (Cause No. PUD 201700151)** – Participated as an expert witness on behalf of OIEC before the OCC in AEP/PSO’s general rate case application to provide testimony on various revenue requirement and rate design issues.
57. **Oncor Electric Delivery Company (Texas), 2017 (PUC Docket No. 46957)** – Participated as an expert witness on behalf of the Steering Committee of Cities before the Texas Public Utility Commission in Oncor’s General Rate Case proceeding to provide testimony on various revenue requirement issues.
58. **EverSource (Massachusetts), 2017 (DPU Docket No. 17-05)** – Participated as an expert witness before the Massachusetts Department of Public Utilities EverSource’s General Rate Case application on behalf of Energy Freedom Coalition of America to provide testimony to address various revenue requirement issues.
59. **El Paso Electric Company (Texas), 2017 (PUC Docket No. 46831)** – Participated as an expert witness on behalf of the City of El Paso before the Texas Public Utility Commission in El Paso’s General Rate Case proceeding to provide testimony on various revenue requirement issues.
60. **Atmos Pipeline Texas (Texas), 2017 (Docket No. 10580)** – Participated as an expert witness on behalf of the City of Dallas before the Texas Railroad Commission in APT’s General Rate Case application, sponsoring testimony to address various revenue requirement proposals.
61. **Empire District Electric Company (Oklahoma), 2017 (Cause No. PUD 201600468)** – Participated as an expert witness on behalf of Oklahoma Industrial Energy Consumers (“OIEC”) before the Oklahoma Corporation Commission in Empire’s General Rate Case application. Sponsoring testimony to address the utility’s overall revenue requirement and rate design proposals.
62. **Caesars Enterprise Service, LLC (Nevada), 2016 (704B Exit Application)** – Participated as an expert witness on behalf of Caesars before the Nevada PUC. Sponsoring written and oral testimony in Caesar’s application to purchase energy and capacity from a provider other than Nevada Power.

63. **Southwestern Electric Power Company (Texas), 2016 (PUC Docket No. 46449)** – Participated as an expert witness on behalf of Cities Advocating Reasonable Deregulation (“CARD Cities”) before the Texas Public Utility Commission in SWEPCO’s general rate case proceeding to provide testimony on various revenue requirement issues.
64. **CenterPoint Texas, 2016 (Docket No. 10567)** – Participated as an expert witness on behalf of City of Houston before the Texas Railroad Commission in CenterPoint’s general rate case application, sponsoring testimony to address the utility’s overall revenue requirement and various rate design proposals.
65. **Entergy Texas, Inc., 2016 (Docket No. 46357)** – Participated as an expert witness on behalf Cities Served by Applicant before the Texas PUC in ETI’s application to amend its Transmission Cost Recovery Factor.
66. **Anchorage Municipal Light and Power, 2016 (Docket No. U-16-060)** – Participated as an expert witness before the Regulatory Commission of Alaska on behalf of Providence Health and Services to provide testimony on the ratemaking treatment of ML&P’s acquired interest in the Beluga River Unit gas field with ratepayer funds.
67. **Arizona Public Service Company, 2016 (Docket No. E-01345A-16-0036)** – Participated as an expert witness before the Arizona Corporation Commission in APS’s General Rate Case application on behalf of Energy Freedom Coalition of America to provide written and oral testimony to address various revenue requirement issues.
68. **Oklahoma Gas & Electric Co. (Arkansas), 2016 (Docket No. 16-052-U)** – Participated as an expert witness on behalf of the Arkansas River Valley Energy Consumers (“ARVEC”)⁵ before the Arkansas Public Service Commission in OG&E’s general rate case application to provide testimony on various revenue requirement, cost of service and rate design issues.
69. **Sierra Pacific Power Company (Nevada), 2016 (Docket No. 16-06006)** – Participated as an expert witness on behalf of the Northern Nevada Utility Customers⁶ before the Nevada PUC in SPPC’s general rate case proceeding. Sponsored testimony on various revenue requirement, depreciation, and rate design issues.
70. **Tucson Electric Power, 2016 (Docket No. E-01933A-15-0322)** – Participated as an expert witness before the Arizona Corporation Commission in TEP’s General Rate Case application, on behalf of Energy Freedom Coalition of America providing written and oral testimony to address the utility’s cost of service study and rate design proposals.
71. **Texas Gas Service, 2016 (Docket No. 10506)** – Participated as an expert witness on behalf of El Paso before the Texas Railroad Commission in TGS’s General Rate Case application, sponsoring testimony to address the utility’s overall revenue requirement and various rate design proposals.
72. **Texas Gas Service, 2016 (Docket No. 10488)** – Participated as an expert witness on behalf of South Jefferson County Service Area (“SJCSA”) before the Texas Railroad Commission in TGS’s General Rate Case application, sponsoring testimony to address the utility’s overall revenue requirement and various rate design proposals.

⁵ ARVEC is an association of industrial manufacturing facilities in northwest Arkansas.

⁶ The Northern Nevada Utility Consumers is a group of large commercial and industrial customers in the SPPC service territory.

73. **Oklahoma Gas and Electric Company, 2016 (Cause No. PUD 201500273)** – Participated as an expert witness on behalf of Oklahoma Industrial Energy Consumers (“OIEC”) before the Oklahoma Corporation Commission in OG&E’s General Rate Case application. Sponsoring testimony to address the utility’s overall revenue requirement and rate design proposals.
74. **Oklahoma Gas & Electric Company, 2016 (Cause No. PUD 201500273)** – Participated as an expert witness on behalf of The Alliance for Solar Choice (“TASC”) before the Oklahoma Corporation Commission to address OG&E’s proposed Distributed Generation (“DG”) rates for solar DG customers.
75. **Anchorage Municipal Light and Power, 2016 (Docket No. U-13-097)** – Participated as an expert witness before the Regulatory Commission of Alaska on behalf of Providence Health and Services to provide testimony on rates and tariffs proposed for customer-owned combined heat and power plant generation.
76. **Oklahoma Natural Gas Company, 2015 (Cause No. PUD 201500213)** – Participated as an expert witness on behalf of the OIEC before the Oklahoma Corporation Commission in ONG’s General Rate Case application. Sponsored testimony to address the utility’s overall revenue requirement and rate design proposals.
77. **Oklahoma Gas & Electric Company, 2015 (Cause No. PUD 201500274)** – Participated as an expert witness on behalf of The Alliance for Solar Choice (“TASC”) before the Oklahoma Corporation Commission to address OG&E’s proposed Distributed Generation (“DG”) rates for solar DG customers.
78. **Nevada Power Company, 2015 (Docket No. 15-07004)** – Participated as an expert witness on behalf of the Southern Nevada Hotel Group (“SNHG”)⁷ before the Nevada PUC. Sponsoring written and oral testimony in NPC’s 2015 Integrated Resource Plan to provide analysis of the On Line transmission line allocation, the Silverhawk plant acquisition, and the Griffith contract termination.
79. **Oklahoma Gas & Electric Company, 2015 (Docket No. 15-034-U)** – Participated as an expert witness on behalf of the Arkansas River Valley Energy Consumers (“ARVEC”) before the Arkansas Public Service Commission in OG&E’s Act 310 application to implement a rider to recover environmental compliance costs.
80. **MGM Resorts, LLC, 2015 (Docket No. 15-05017)** – Participated as an expert witness on behalf of the MGM Resorts, LLC before the Nevada PUC. Sponsoring written and oral testimony in MGM’s application to purchase energy and capacity from a provider other than Nevada Power.
81. **Entergy Arkansas, 2015 (Docket No. 15-015-U)** – Participated as an expert witness on behalf of the Hospital and Higher Education Group (“HHEG”) an intervener group that includes the University of Arkansas and several hospitals before the Arkansas PSC in Entergy’s general rate case to provide testimony on various revenue requirement issues.

⁷ The Southern Nevada Hotel Group is comprised of Boyd Gaming, Caesars Entertainment, MGM Resorts, Station Casinos, Venetian Casino Resort, and Wynn Las Vegas.

82. **Public Service Company of Oklahoma, 2015 (Cause No. PUD 201500208)** – Participated as an expert witness on behalf of OIEC before the OCC in AEP/PSO’s general rate case application to provide testimony on various cost-of-service issues and on the utility’s overall revenue requirement and rate design proposals.
83. **Nevada Power Company, 2014 (Docket No. 14-05003)** – Participated as an expert witness on behalf of the Southern Nevada Hotel Group (“SNHG”) before the Nevada PUC. Sponsored written and oral testimony in NPC environmental compliance case, called the Emissions Reduction and Capacity Replacement case. The main focus of our testimony was our recommendation to eliminate the \$438M Moapa solar project from the compliance plan.
84. **Nevada Power Company, 2014 (Docket No. 14-05004)** – Participated as an expert witness on behalf of the Southern Nevada Hotel Group before the Nevada PUC to sponsor written and oral testimony in both the revenue requirement phase and the rate design phase of the proceedings to establish prospective cost-of-service based rates for the power company.
85. **Oklahoma Gas and Electric Co., 2014 (Cause No. PUD 201400229)** – Participated as an expert witness on behalf of Oklahoma Industrial Energy Consumers (“OIEC”) in OG&E’s Environmental Compliance and Mustang Modernization Plan before the Oklahoma Corporation Commission to provide testimony addressing the economics and rate impacts of the plan.
86. **Sourcegas Arkansas, Inc., 2014 (Docket No. 13-079-U)** Participated as an expert witness on behalf of the Hospital and Higher Education Group (“HHEG”), an intervener group that includes the University of Arkansas and several hospitals before the Arkansas PSC in SGA’s general rate case to provide testimony on various revenue requirement issues.
87. **Anchorage Municipal Light and Power, 2014 (Docket No. U-13-184)** – Participated as an expert witness before the Alaska Regulatory Utility Commission on behalf of Providence Health and Services to provide testimony on various revenue requirement and cost of service issues.
88. **Public Service Company of Oklahoma, 2014 (Cause No. PUD 201300217)** – Participated as an expert witness on behalf of OIEC before the OCC in AEP/PSO’s general rate case application to provide testimony on various cost-of-service issues and on the utility’s overall revenue requirement and rate design proposals.
89. **Entergy Texas Inc., 2013 (PUC Docket No. 41791)** – Participated as an expert witness on behalf of the Cities⁸ in ETI’s general rate case to provide testimony on various cost of service issues and on the utility’s overall revenue requirement.
90. **MidAmerican/NV Energy Merger, 2013 (Docket No. 13-07021)** – Participated as an expert witness on behalf of the Southern Nevada Hotel Group (“SNHG”) before the Nevada PUC. Sponsored testimony to address various issues raised in the proposed acquisition of NV Energy by MidAmerican Energy Holdings Company, including capital structure and acquisition premium recovery issues.
91. **Entergy Arkansas, 2013 (Docket No. 13-028-U)** – Participated as an expert witness on behalf of the Hospital and Higher Education Group (“HHEG”) an intervener group that includes the University of Arkansas and several hospitals before the Arkansas PSC in Entergy’s general rate case to provide testimony on various revenue requirement issues.

⁸ The Cities include Beaumont, Conroe, Groves, Houston, Huntsville, Orange, Navasota, Nederland, Pine Forest, Pinehurst, Port Arthur, Port Neches, Rose City, Shenandoah, Silsbee, Sour Lake, Vidor, and West Orange.

92. **Sierra Pacific Power Company, 2013 (Docket No. 13-06002)** – Participated as an expert witness on behalf of the Northern Nevada Utility Customers⁹ before the Nevada PUC in SPPC’s general rate case proceeding to provide testimony on various cost of service and revenue requirement issues. Sponsored written and oral testimony in the depreciation phase, the revenue requirement phase and the rate design phase of these proceedings.
93. **Gulf Power Company, 2013 (Docket No. 130140-EI)** – Participated as an expert witness on behalf of the Office of Public Counsel before the Florida Commission in Gulf Power’s general rate case proceeding to provide testimony on various revenue requirement issues.
94. **Public Service Company of Oklahoma, 2013 (Cause No. PUD 201200054)** – Participated as an expert witness on behalf of the OIEC before the Oklahoma Corporation Commission (“OCC”) to provide testimony in PSO’s application seeking Commission approval of its settlement agreement with EPA.
95. **Southwestern Electric Power Company, 2012 (PUC Docket No. 40443)** – Participated as an expert witness on behalf of Cities Advocating Reasonable Deregulation (“CARD Cities”) before the Texas Public Utility Commission in SWEPCO’s general rate case proceeding to provide testimony on various cost of service issues and on the utility’s overall revenue requirement.
96. **Doyon Utilities, 2012 Alaska Rate Case (Docket No. TA7-717)** – Participated as an expert witness consultant on behalf of the Department of Defense to provide expert testimony in twelve rate case reviews for the utility systems of Fort Wainwright, Fort Greely and Joint Base Elmendorf-Richardson before the Regulatory Commission of Alaska.
97. **University of Oklahoma, 2012** – Participated as an expert witness on behalf of the University of Oklahoma to provide expert testimony on various revenue requirement issues in the University’s general rate case with the Corix Group, which provides utility services to the University.
98. **Public Service Company of Oklahoma, 2012 (Cause No. PUD 201200079)** – Participated as an expert witness on behalf of the OIEC before the Oklahoma Corporation Commission to provide expert testimony addressing the utility’s request to earn additional compensation on a 510MW purchased power agreement with Exelon
99. **Centerpoint Energy Texas Gas, 2012 (Docket No. GUD 10182)** – Participated as an expert witness on behalf of the Steering Committee of Cities before the Texas Railroad Commission to provide expert testimony on various revenue requirement issues.
100. **Entergy Texas Inc., 2012 (PUC Docket No. 39896)** – Participated as an expert witness on behalf of the Cities in ETI’s general rate case to provide testimony on various cost of service issues and on the utility’s overall revenue requirement.
101. **Oklahoma Natural Gas Company, 2012 (Cause No. PUD 2012-029)** – Participated as an expert witness on behalf of the OIEC before the OCC in ONG’s Performance Based Rate (“PBR”) application seeking Commission approval of a requested rate increase based upon formula results for 2011.

⁹ The Northern Nevada Utility Consumers is a group of large commercial and industrial customers in the SPPC service territory.

102. **University of Oklahoma, 2012** – Assisted the University of Oklahoma with an audit of the costs associated with its six utility operations and its contract with the Corix Group to provide utility services to the university.
103. **Oklahoma Gas and Electric Company, 2012 (Cause No. PUD 2011-186)** – Participated as an expert witness on behalf of the OIEC before the OCC in OG&E’s application seeking Commission approval of a special contract with Oklahoma State University and a wind energy purchase agreement in connection therewith.
104. **Empire Electric Company, 2011, (Cause No. PUD 11-082)** – Participated as an expert witness on behalf of Enbridge before the OCC in Empire’s rate case to provided testimony in both the revenue requirement and rate design phases of the proceedings to establish prospective cost-of-service based rates for the power company.
105. **Nevada Power Company, 2011, (Docket No. 11-04010)** - Participated as an expert witness on behalf of the Southern Nevada Hotel Group (“SNHG”) before the Nevada PUC. Sponsored written and oral testimony to address proposed changes to the Company’s customer deposit rules.
106. **Nevada Power Company, 2011, (Docket No. 11-06006)** - Participated as an expert witness on behalf of the Southern Nevada Hotel Group before the Nevada PUC. Sponsored written and oral testimony in both the revenue requirement phase and the rate design phase of the proceedings to establish prospective cost-of-service based rates for the power company.
107. **Public Service Company of Oklahoma, 2011 (Cause No. PUD 2011-106)** – Participated as an expert witness on behalf of the OIEC before the OCC in PSO’s application seeking rider recovery of third party SPP transmission costs and fees.
108. **Oklahoma Gas and Electric Company, 2011 (Cause No. PUD 2011-087)** – Participated as an expert witness on behalf of OIEC before the OCC in OG&E’s rate case to provided testimony in both the revenue requirement and rate design phases of the proceedings to establish prospective cost-of-service based rates for the power company.
109. **Oklahoma Gas & Electric Company, 2011 (Docket No. 10-109-U)** – Participated as an expert witness on behalf of Gerdau Macsteel before the Arkansas Public Service Commission in OG&E’s application to recover Smart Grid costs to make recommendations regarding the allocation of the Smart Grid costs.
110. **Oklahoma Gas & Electric Company, 2011 (Cause No. PUD 2011-027)** – Participated as an expert witness on behalf of the OIEC before the OCC in OG&E’s application seeking to include retiree medical expense in the Company’s pension tracker mechanism.
111. **Public Service Company of Oklahoma, 2011 (Cause No. PUD 2010-50)** – Participated as an expert witness on behalf of OIEC before the Oklahoma Corporation Commission in AEP/PSO’s application to recover ice storm O&M expenses through a regulatory asset/rider mechanism to address tax impact and return issues in the proposed rider.
112. **Public Service Company of Colorado, 2011 (Docket No. 10AL-908E)** – Participated as an expert witness on behalf of the Colorado Retail Council (“CRC”) before the Colorado Public Utilities Commission providing written and live testimony to address PSCo’s proposed Environmental Tariff.

113. **Oklahoma Gas & Electric Company, 2011 (Docket No. 10-067-U)** – Participated as an expert witness on behalf of the Northwest Arkansas Industrial Energy Consumers (“NWIEC”)¹⁰ before the Arkansas Public Service Commission in OG&E’s general rate case application to provide testimony on various revenue requirement, cost of service and rate design issues.
114. **Oklahoma Gas & Electric Company, 2010 (Cause No. PUD 2010-146)** – Participated as an expert witness on behalf of the OIEC before the OCC in OG&E’s application seeking rider recovery of third party SPP transmission costs and SPP administration fees.
115. **Massachusetts Electric Co. & Nantucket Electric Co. d/b/a National Grid, 2010 (Docket No. DPU 10-54)** – Participated as an expert witness providing both written and live testimony before the Massachusetts Department of Public Utilities on behalf of the Associated Industries of Massachusetts (“AIM”) to address the Company’s proposed participation in the 438MW Cape Wind project in Nantucket Sound.
116. **Public Service Company of Oklahoma, 2010 (Cause No. PUD 2010-50)** – Participated as an expert witness on behalf of the OIEC before the OCC in AEP/PSO’s general rate case application to provide testimony on various cost-of-service issues and on the utility’s overall revenue requirement and rate design proposals.
117. **Texas-New Mexico Power Co., 2010 (Docket 38480)** – Participated as an expert witness on behalf of the Alliance of Texas Municipalities (“ATM”) before the Texas PUC in TMNP’s general rate case application to address various revenue requirement and rate design issues to establish prospective cost-of-service based rates.
118. **Southwestern Public Service Co., 2010 (PUCT Docket No. 38147)** – Participated as an expert witness on behalf of the Alliance of Xcel Municipalities (“AXM”) in the SPS general rate case application to provide testimony before the Texas Public Utility Commission regarding rate base and operating expense issues and sponsor the AXM Accounting Exhibits.
119. **Oklahoma Gas & Electric Company, 2010 (Cause No. PUD 2010-37)** – Participated as an expert witness on behalf of OIEC before the OCC to address the preapproval and ratemaking treatment of OG&E’s 220MW self-build wind project.
120. **Oklahoma Gas & Electric Company, 2010 (Cause No. PUD 2010-29)** – Participated as an expert witness on behalf of the OIEC before the OCC in OG&E’s application seeking pre-approval of deployment of smart-grid technology and rider-recovery of the associated costs. Sponsored written testimony to address smart-grid deployment and time-differentiated fuel rates.
121. **Public Service Company of Oklahoma, 2010 (Cause No. PUD 2010-01)** – Participated as an expert witness on behalf of the OIEC before the OCC in the Company’s proposed Green Energy Choice Tariff. Sponsored testimony to address the pricing and ratemaking treatment of the Company’s proposed wind subscription tariff.

¹⁰NWIEC is an association of industrial manufacturing facilities in northwest Arkansas.

122. **Nevada Power Company, 2010 (Docket No. 10-02009)** – Participated as an expert witness on behalf of the Southern Nevada Hotel Group (“SNHG”) before the Nevada PUC to provide testimony in NPC’s Internal Resource Plan to address the ratemaking treatment of the proposed ON Line transmission line.
123. **Entergy Texas Inc., 2010 (PUC Docket No. 37744)** – Participated as an expert witness on behalf of the Cities in ETI’s general rate case to provide testimony on various cost of service issues and on the utility’s overall revenue requirement.
124. **El Paso Electric Company, 2010 (PUC Docket No. 37690)** – Participated as an expert witness on behalf of the City of El Paso in the EPI general rate case to provide testimony on various cost of service issues and on the utility’s overall revenue requirement.
125. **Public Service Company of Oklahoma, 2009 (Cause No. 09-196)** – Participated as an expert witness on behalf of the OIEC before the OCC in PSO’s application for approval of DSM programs and cost recovery. Sponsored testimony to address program costs, lost revenue recovery, cost allocations and incentives.
126. **Oklahoma Gas and Electric Company, 2009 (Cause No. PUD 09-230 and 09-231)** – Participated as an expert witness on behalf of OIEC before the OCC in OG&E’s application to add wind resources from two purchased power contracts. Sponsored written testimony to address the proper ratemaking treatment of the contract costs and the renewable energy certificates.
127. **Oklahoma Gas and Electric Company, 2009 (Cause No. PUD 08-398)** – Participated as an expert witness on behalf of OIEC before the OCC in OG&E’s rate case. Provided testimony in both the revenue requirement and rate design phases of the proceedings to establish prospective cost-of-service based rates for the power company.
128. **Nevada Power Company, 2009, (Docket No. 08-12002)** - Participated as an expert witness on behalf of the Southern Nevada Hotel Group before the Nevada PUC. Sponsored written and oral testimony in both the revenue requirement phase and the rate design phase of the proceedings to establish prospective cost-of-service based rates for the power company.
129. **Public Service Company of Oklahoma, 2009 (Cause No. 09-031)** – Participated as an expert witness on behalf of OIEC before the OCC in PSO’s application to add wind resources from two purchased power contracts. Sponsored written testimony to address the proper ratemaking treatment of the contract costs and the renewable energy certificates.
130. **Oklahoma Natural Gas Co., 2009 (Cause No. PUD 08-348)** – Participated as an expert witness on witness on behalf of the OIEC before the OCC in ONG’s application to establish a Performance Based Rate tariff. Sponsored both written and oral testimony to address the merits of the utility’s proposed PBR.
131. **Rocky Mountain Power, 2009 (Docket No. 08-035-38)** – Participated as an expert witness on behalf of the Division of Public Utilities (Staff) in PacifiCorp’s general rate case to provide testimony on various revenue requirement issues.
132. **Texas-New Mexico Power Co., 2008 (Docket 36025)** – Participated as an expert witness on behalf of the Alliance of Texas Municipalities (“ATM”) before the Texas PUC in TMNP’s general rate case application to address various revenue requirement and rate design issues to establish prospective cost-of-service based rates.

133. **Public Service Company of Oklahoma, 2008 (Cause No. 08-144)** – Participated as an expert witness on behalf of the OIEC before the OCC in PSO’s general rate case application to address revenue requirement and rate design issues to establish prospective cost-of-service based rates.
134. **Public Service Company of Oklahoma, 2008 (Cause No. 08-150)** – Participated as an expert witness on behalf of the OIEC before the OCC to address PSO’s calculation of its Fuel Clause Adjustment for 2008.
135. **Oklahoma Gas and Electric Company, 2008 (Cause No. PUD 08-059)** – Participated as an expert witness on behalf of the OIEC before the OCC in OG&E’s application seeking authorization of its Demand Side Management (“DSM”) programs and the establishment of a DSM Rider to recover program costs, lost revenues and utility incentives.
136. **Entergy Gulf States, 2008 (PUC Docket No. 34800, SOAH Docket No. 473-08-0334)** – Participated as an expert witness on behalf of the Cities in EGSI’s general rate case to provide testimony on various cost of service issues and on the utility’s overall revenue requirement.
137. **Public Service Company of Oklahoma, 2008 (Cause No. 07-465)** – Participated as an expert witness on behalf of the OIEC before the OCC in PSO’s application to recover the pre-construction costs of the cancelled Red Rock coal generation facility.
138. **Oklahoma Gas and Electric Company, 2008 (Cause No. 07-447)** – Participated as an expert witness on behalf of the OIEC before the OCC in OG&E’s application seeking authorization to recover the pre-construction costs of the cancelled Red Rock coal generation facility using proceeds from sales of excess SO₂ allowances.
139. **Rocky Mountain Power, 2008 (Docket No. 07-035-93)** – Participated as an expert witness on behalf of Division of Public Utilities (Staff) in PacifiCorp’s general rate case to provide testimony on various revenue requirement issues.
140. **Public Service Company of Oklahoma, 2008 (Cause No. PUD 07-449)** – Participated as an expert witness on behalf of the OIEC before the OCC in PSO’s application seeking authorization of its Demand Side Management (“DSM”) programs and the establishment of a DSM Rider to recover program costs, lost revenues and utility incentives.
141. **Public Service Company of Oklahoma, 2008 (Cause No. PUD 07-397)** – Participated as an expert witness on behalf of OIEC before the OCC in PSO’s application seeking authorization to defer storm damage costs in a regulatory asset account and to recover the costs using the proceeds from sales of excess SO₂ allowances.
142. **Oklahoma Gas & Electric Co., 2007 (Cause No. PUD 07-012)** – Participated as an expert witness on behalf of OIEC before the OCC in OG&E’s application seeking pre-approval to construct the Red Rock coal plant to address the Company’s proposed rider recovery mechanism.
143. **Oklahoma Natural Gas Co., 2007 (Cause No. PUD 07-335)** – Participated as an expert witness on behalf of the OIEC before the OCC in ONG’s application proposing alternative cost recovery for the Company’s ongoing capital expenditures through the proposed Capital Investment Mechanism Rider (“CIM Rider”). Sponsored testimony to address ONG’s proposal.

144. **Public Service Company of Oklahoma, 2007 (Cause No. PUD 06-030)** – Participated as an expert witness on behalf of the OIEC before the OCC in PSO’s application seeking a used and useful determination for its planned addition of the Red Rock coal plant to address the Company’s use of debt equivalency in the competitive bidding process for new resources.
145. **Public Service Company of Oklahoma, 2006 (Cause No. PUD 06-285)** – Participated as an expert witness on behalf of the OIEC before the OCC in PSO’s general rate case application to address various revenue requirement and rate design issues to establish prospective cost-of-service based rates.
146. **Nevada Power Company, 2007, (Docket No. 07-01022)** - Participated as an expert witness on behalf of the MGM MIRAGE before the Nevada PUC in Nevada Power Company’s deferred energy docket to determine the level of prudent company expenditures for fuel and purchased power.
147. **Nevada Power Company, 2006, (Docket No. 06-11022)** - Participated as an expert witness on behalf of the MGM MIRAGE properties before the Nevada PUC. Sponsored written and oral testimony in both the revenue requirement phase and the rate design phase of the proceedings to establish prospective cost-of-service based rates for the power company.
148. **Southwestern Public Service Co., 2006 (PUCT Docket No. 37766)** – Participated as an expert witness on behalf of the Alliance of Xcel Municipalities (“AXM”) in the SPS general rate case application. Provided testimony before the Texas Public Utility Commission regarding rate base and operating expense issues and sponsored the Accounting Exhibits on behalf of AXM.
149. **Atmos Energy Corp., Mid-Tex Division, 2006 (Texas GUD 9676)** – Participated as an expert witness in the Atmos Mid-Tex general rate case application on behalf of the Atmos Texas Municipalities (“ATM”). Provided written and oral testimony before the Railroad Commission of Texas regarding the revenue requirements of Mid-Tex including various rate base, operating expense, depreciation and tax issues. Sponsored the Accounting Exhibits for ATM.
150. **Nevada Power Company, 2006 (Docket No. 06-06007)** – Participated as an expert witness on behalf of the MGM MIRAGE in the Sinatra Substation Electric Line Extension and Service Contract case. Provided both written and oral testimony before the Nevada Public Utility Commission to provide the Commission with information as to why the application is consistent with the line extension requirements of Rule 9 and why the cost recovery proposals set forth in the application provide a least cost approach to adding necessary new capacity in the Las Vegas strip area.
151. **Public Service Co. of Oklahoma, 2006 (Cause No. PUD 05-00516)** - Participated as an expert witness on behalf of the OIEC to review PSO’s application for a “used and useful” determination of its proposed peaking facility.
152. **Oklahoma Gas and Electric Co., 2006 (Cause No. PUD 06-00041)** – Participated as an expert witness on behalf of the OIEC in OG&E’s application to propose an incentive sharing mechanism for SO₂ allowance proceeds.
153. **Chermac Energy Corporation, 2006 (Cause No. PUD 05-00059 and 05-00177)** – Participated as an expert witness on behalf of the OIEC in Chermac’s PURPA application. Sponsored written responsive and rebuttal testimony to address various rate design issues arising under the application.

154. **Oklahoma Gas and Electric Co., 2006 (Cause No. PUD 05-00140)** – Participated as an expert witness on behalf of the OIEC in OG&E’s 2003 and 2004 Fuel Clause reviews. Sponsored written testimony to address the purchasing practices of the Company, its transactions with affiliates, and the prices paid for natural gas, coal and purchased power.

155. **Nevada Power Company, 2006, (Docket No. 06-01016)** - Participated as an expert witness on behalf of the MGM MIRAGE properties before the Nevada PUC. Sponsored written testimony in NPC’s deferred energy docket to determine the level of prudent company expenditures for fuel and purchased power.

156. **Oklahoma Gas and Electric Co., 2005 (Cause No. PUD 05-151)** – Participated as an expert witness on behalf of the OIEC in OG&E’s general rate case application. Sponsored both written and oral testimony before the OCC to address various revenue requirement and rate design issues for the purpose of setting prospective cost-of-service based rates.

157. **Oklahoma Natural Gas Co., 2005 (Cause No. PUD 04-610)** – Participated as an expert witness on behalf of the Attorney General of Oklahoma. Sponsored written and oral testimony to address numerous rate base, operating expense and depreciation issues for the purpose of setting prospective cost-of-service based rates.

158. **CenterPoint Energy Arkla, 2004 (Cause No. PUD 04-0187)** – Participated as an expert witness on behalf of the Attorney General of Oklahoma: Sponsored written testimony to provide the OCC with analysis from an accounting and ratemaking perspective of the Co.’s proposed change in depreciation rates from an Average Life Group to an Equal Life Group methodology. Addressed the Co.’s proposed increase in depreciation rates associated with increased negative salvage value calculations.

159. **Public Service Co. of Oklahoma, 2004 (Cause No. PUD 02-0754)** – Participated as an expert witness on behalf of the OIEC. Sponsored written testimony (1) making adjustments to PSO’s requested recovery of an ICR programming error, (2) correcting errors in the allocation of trading margins on off-system sales of electricity from AEP East to West and among the AEP West utilities and (3) recommending an annual rather than a quarterly change in the FAC rates.

160. **PowerSmith Cogeneration Project, 2004 (Cause No. PUD 03-0564)** - Participated as an expert witness on behalf of the OIEC to provide the OCC with direction in setting an avoided cost for the PowerSmith Cogeneration project under PURPA requirements. Provided both written and oral testimony on the provisions of the proposed contract under PURPA:

161. **Electric Utility Rules for Affiliate Transactions, 2004 (Cause No. RM 03-0003)** – Participated as a consultant on behalf of the OIEC to draft comments to assist the OCC in developing rules for affiliate transactions. Assisted in drafting the proposed rules. Successful in having the Lower of Cost or Market rule adopted for affiliate transactions in Oklahoma.

162. **Nevada Power Company, 2003, (Docket No. 03-10001)** - Participated as an expert witness on behalf of the MGM MIRAGE properties before the Nevada PUC. Sponsored written and oral testimony in both the revenue requirement phase and the rate design phase of the proceedings to establish prospective cost-of-service based rates for the power company.

163. **Nevada Power Company, 2003, (Docket No. 03-11019)** - Participated as an expert witness on behalf of the MGM MIRAGE before the Nevada PUC in Nevada Power Company’s deferred energy docket to determine the level of prudent company expenditures for fuel and purchased power.

164. **Public Service Company of Oklahoma, 2003 (Cause No. PUD 03-0076)** – Participated as an expert witness on behalf of the OIEC before the OCC in PSO’s general rate case application to address various revenue requirement and rate design issues to establish prospective cost-of-service based rates.
165. **Oklahoma Gas & Electric Co., 2003 (Cause No. PUD 03-0226)** – Participated as an expert witness on behalf of the OIEC. Provided both written and oral testimony before the OCC to determine the appropriate level to include in rates for natural gas transportation and storage services acquired from an affiliated company.
166. **Nevada Power Company, 2003 (Docket No. 02-5003-5007)** - Participated as an expert witness on behalf of the MGM Mirage before the Nevada PUC. Sponsored written and oral testimony to calculate the appropriate exit fee in MGM Mirage’s 661 Application to leave the system.
167. **McCarthy Family Farms, 2003** – Participated as a consultant to assist McCarthy Family Farms in converting a biomass and biosolids composting process into a renewable energy power producing business in California.
168. **Bice v. Petro Hunt, 2003 (ND, Supreme Court No. 20030306)** - Participated as an expert witness in a class certification proceeding to provide cost-of-service calculations for royalty valuation deductions for natural gas gathering, dehydration, compression, treatment and processing fees in North Dakota.
169. **Nevada Power Company, 2003 (Docket No. 03-11019)** - Participated as a consulting expert on behalf of the MGM Mirage before the Nevada PUC in Nevada Power Company’s deferred energy docket to determine the level of prudent company expenditures for fuel and purchased power. Provided written and oral testimony on the reasonableness of the cost allocations to the utility’s various customer classes.
170. **Wind River Reservation, 2003 (Fed. Claims Ct. No. 458-79L, 459-79L)** – Participated as a consulting expert on behalf of the Shoshone and Arapaho Tribes to provide cost-of-service calculations for royalty valuation deductions for gathering, dehydration, treatment and compression of natural gas and the reasonableness of deductions for gas transportation.
171. **Oklahoma Gas & Electric Co., 2002 (Cause No. PUD 01-0455)** – Participated as an expert witness on behalf of the OIEC before the OCC. Sponsored written and oral testimony on numerous revenue requirement issues including rate base, operating expense and rate design issues to establish prospective cost-of-service based rates.
172. **Nevada Power Company, 2002 (Docket No. 02-11021)** - Participated as an expert witness on behalf of the MGM Mirage before the Nevada PUC in Nevada Power Company’s deferred energy docket to determine the level of prudent company expenditures for fuel and purchased power and to make recommendations with respect to rate design.
173. **Nevada Power Company, 2002 (Docket No. 01-11029)** - Participated as a consulting expert on behalf of the MGM Mirage before the Nevada PUC in Nevada Power Company’s deferred energy docket to determine the level of prudent company expenditures for fuel and purchased power included in the Company’s \$928 million deferred energy balances.

174. **Nevada Power Company, 2002 (Docket No. 01-10001)** - Participated as an expert witness on behalf of the MGM Mirage before the Nevada PUC. Sponsored written and oral testimony in both the revenue requirement phase and the rate design phase of the proceedings to establish prospective cost-of-service based rates for the power company.
175. **Chesapeake v. Kinder Morgan, 2001 (CIV-00-397L)** - Participated as an expert witness on behalf of Chesapeake Energy in a gas gathering dispute. Sponsored testimony to calculate and support a reasonable rate on the gas gathering system. Performed necessary calculations to determine appropriate levels of operating expense, depreciation and cost of capital to include in a reasonable gathering charge and developed an appropriate rate design to recover these costs.
176. **Southern Union Gas Company, 2001** - Participated as a consultant to the City of El Paso in its review of SUG's gas purchasing practices, gas storage position, and potential use of financial hedging instruments and ratemaking incentives to devise strategies to help shelter customers from the risk of high commodity price spikes during the winter months.
177. **Nevada Power Company, 2001** - Participated as an expert witness on behalf of the MGM-Mirage, Park Place and Mandalay Bay Group before the Nevada Public Utility Commission to review NPC's Comprehensive Energy Plan (CEP) for the State of Nevada and make recommendations regarding the appropriate level of additional costs to include in rates for the Company's prospective power costs associated with natural gas and gas transportation, coal and coal transportation and purchased power.
178. **Bridenstine v. Kaiser-Francis Oil Co. et al., 2001 (CJ-95-54)** - Participated as an expert witness on behalf of royalty owner plaintiffs in a valuation dispute regarding gathering, dehydration, metering, compression, and marketing costs. Provided cost-of-service calculations to determine the reasonableness of the gathering rate charged to the royalty interest. Also provided calculations as to the average price available in the field based upon a study of royalty payments received on other wells in the area.
179. **Klatt v. Hunt et al., 2000 (ND)** - Participated as an expert witness and filed report in United States District Court for the District of North Dakota in a natural gas gathering contract dispute to calculate charges and allocations for processing, sour gas compression, treatment, overhead, depreciation expense, use of residue gas, purchase price allocations, and risk capital.
180. **Oklahoma Gas and Electric Co., 2000 (Cause No. PUD 00-0020)** - Participated as an expert witness on behalf of the OIEC before the OCC. Sponsored testimony on OG&E's proposed Generation Efficiency Performance Rider (GEPR). Provided a list of criteria with which to measure a utility's proposal for alternative ratemaking. Recommended modifications to the Company's proposed GEPR to bring it within the boundaries of an acceptable alternative ratemaking formula.
181. **Oklahoma Gas and Electric Co., 1999** - Participated as an expert witness on behalf of the OIEC before the OCC. Sponsored testimony on OG&E's proposed Performance Based Ratemaking (PBR) proposal including analysis of the Company's regulated return on equity, fluctuations in the capital investment and operating expense accounts of the Company and the impact that various rate base, operating expense and cost of capital adjustments would have on the Company's proposal.
182. **Nevada Power Company, 1999 (Docket No. 99-7035)** - Participated as an expert witness on behalf of the Mirage, Park Place and Mandalay Bay Group before the Nevada PUC. Sponsored written and oral testimony addressing the appropriate ratemaking treatment of the Company's deferred energy balances, prospective power costs for natural gas, coal and purchased power and deferred capacity payments for purchased power.

183. **Nevada Power Company, 1999 (Docket No. 99-4005)** - Participated as an expert witness on behalf of the Mirage, Park Place and Mandalay Bay Group before the Nevada PUC. Sponsored written and oral testimony to unbundle the utility services of the NPC and to establish the appropriate cost-of-service allocations and rate design for the utility in Nevada's new competitive electric utility industry.
184. **Nevada Power Company, 1999 (Docket No. 99-4005)** - Participated as an expert witness on behalf of the Mirage, Park Place and Mandalay Bay Group before the Nevada PUC. Sponsored written and oral testimony to establish the cost-of-service revenue requirement of the Company.
185. **Nevada Power/Sierra Pacific Merger, 1998 (Docket No. 98-7023)** - Participated as an expert witness on behalf of the Mirage and MGM Grand before the Nevada PUC. Sponsored written and oral testimony to establish (1) appropriate conditions on the merger (2) the proper sequence of regulatory events to unbundle utility services and deregulate the electric utility industry in Nevada (3) the proper accounting treatment of the acquisition premium and the gain on divestiture of generation assets. The recommendations regarding conditions on the merger, the sequence of regulatory events to unbundle and deregulate, and the accounting treatment of the acquisition premium were specifically adopted in the Commission's final order.
186. **Oklahoma Natural Gas Company, 1998 (Cause No. PUD 98-0177)** - Participated as an expert witness in ONG's unbundling proceedings before the OCC. Sponsored written and oral testimony on behalf of Transok, LLC to establish the cost of ONG's unbundled upstream gas services. Substantially all of the cost-of-service recommendations to unbundle ONG's gas services were adopted in the Commission's interim order.
187. **Public Service Company of Oklahoma, 1997 (Cause No. PUD 96-0214)** - Audited both rate base investment and operating revenue and expense to determine the Company's revenue requirement and cost-of-service. Sponsored written testimony before the OCC on behalf of the OIEC.
188. **Oklahoma Natural Gas /Western Resources Merger, 1997 (Cause No. PUD 97-0106)** - Sponsored testimony on behalf of the OIEC regarding the appropriate accounting treatment of acquisition premiums resulting from the purchase of regulated assets.
189. **Oklahoma Gas and Electric Co., 1996 (Cause No. PUD 96-0116)** - Audited both rate base investment and operating income. Sponsored testimony on behalf of the OIEC for the purpose of determining the Company's revenue requirement and cost-of-service allocations.
190. **Oklahoma Corporation Commission, 1996** - Provided technical assistance to Commissioner Anthony's office in analyzing gas contracts and related legal proceedings involving ONG and certain of its gas supply contracts. Assignment included comparison of pricing terms of subject gas contracts to portfolio of gas contracts and other data obtained through annual fuel audits analyzing ONG's gas purchasing practices.
191. **Tenkiller Water Company, 1996** - Provided technical assistance to the Attorney General of Oklahoma in his review of the Company's regulated cost-of-service for the purpose of setting prospective utility rates.
192. **Arkansas Oklahoma Gas Company, 1995 (Cause No. PUD 95-0134)** - Sponsored written and oral testimony before the OCC on behalf of the Attorney General of Oklahoma regarding the price of natural gas on AOG's system and the impact of AOG's proposed cost of gas allocations and gas transportation rates and tariffs on AOG's various customer classes.

193. **Enogex, Inc., 1995 (FERC 95-10-000)** - Analyzed Enogex's application before the FERC to increase gas transportation rates for the Oklahoma Independent Petroleum Association and made recommendations regarding revenue requirement, cost-of-service and rate design on behalf of independent producers and shippers.
194. **Oklahoma Natural Gas Company, 1995 (Cause No. PUD 94-0477)** - Analyzed a portfolio of ONG's gas purchase contracts in the Company's Payment-In-Kind (PIC) gas purchase program and made recommendations to the OCC Staff on behalf of Terra Nitrogen, Inc. regarding the inappropriate profits made by ONG on the sale of the gas commodity through the PIC program pricing formula. Also analyzed the price of gas on ONG's system, ONG's cost-of-service based rates, and certain class cross-subsidizations in ONG's existing rate design.
195. **Arkansas Louisiana Gas Company, 1994 (Cause No. PUD 94-0354)** - Planned and supervised the rate case audit for the OCC Staff and reviewed the workpapers and testimony of the other auditors on the case. Sponsored cost-of-service testimony on cash working capital and developed policy recommendations on post test year adjustments.
196. **Empire District Electric Company, 1994 (Cause No. PUD 94-0343)** - Planned and supervised the rate case audit for the OCC Staff and reviewed the workpapers and testimony of other auditors. Sponsored cost-of-service testimony on rate base investment areas including cash working capital.
197. **Oklahoma Natural Gas Company, 1992 through 1993 (Cause No. PUD 92-1190)** - Planned and supervised the rate case audit of ONG for the OCC Staff. Reviewed all workpapers and testimony of the other auditors on the case. Sponsored written and oral testimony on numerous cost-of-service adjustments. Analyzed ONG's gas supply contracts under the Company's PIC program.
198. **Oklahoma Gas and Electric Company, 1991 through 1992 (Cause No. PUD 91-1055)** - Audited the rate base, operating revenue and operating expense accounts of OG&E on behalf of the OCC Staff. Sponsored written and oral testimony on numerous revenue requirement adjustments to establish the appropriate level of costs to include for the purpose of setting prospective rates.

**SOAH DOCKET NO. 473-21-0538
PUC DOCKET NO. 51415**

**APPLICATION OF SOUTHWESTERN § BEFORE THE STATE OFFICE
ELECTRIC POWER COMPANY FOR § OF
AUTHORITY TO CHANGE RATES § ADMINISTRATIVE HEARINGS**

**DIRECT TESTIMONY AND EXHIBITS
OF MARK E. GARRETT**

**EXHIBIT MG-2:
SCHEDULES**

SOUTHWESTERN ELECTRIC POWER COMPANY
 Cities Advocating Reasonable Deregulation Summary of Recommendations
 Docket No. 51415; Test Year End March 31, 2020

Line No.	Description	Reference	Rate Impact
1	SWEPCO Payroll	Exhibit MG-2.1	\$ (623,862)
2	AEPSC Payroll	Exhibit MG-2.2	(1,489,989)
3	SWEPCO STI	Exhibit MG-2.3	(911,967)
4	AEPSC STI	Exhibit MG-2.4	(391,044)
5	LTI	Exhibit MG-2.5	(371,024)
6	OPEB SFAS 106 Expense	Exhibit MG-2.6	(2,117,108)
7	Vegetation Management	Exhibit MG-2.7	(5,000,000)
8	Self Insurance Expense	Exhibit MG-2.8	(1,689,700)
9	Dolet Hills Depreciation Expense	Exhibit MG-2.9	(705,313)
10	Amortization of Unprotected EDFIT	Exhibit MG-2.10	(7,602,161)
11	Depreciation Rate Adjustment	Exhibit MG-2.11	(6,940,283)
12	Total Operating Income Adjustments		<u>\$ (27,842,451)</u>

SOUTHWESTERN ELECTRIC POWER COMPANY
 Cities Advocating Reasonable Deregulation SWEPCO Payroll Expense Adjustment
 Docket No. 51415; Test Year End March 31, 2020

Line No.	Description	Amount
1	Test Year SWEPCO Payroll Expense ¹	\$ 74,407,712
2	Effective Change in Base Pay ²	<u>100.87%</u>
3	CARD Annualized Payroll Expense	\$ 75,055,059
4	SWEPCO Proposed Payroll Expense ³	<u>76,551,424</u>
5	CARD Pro Forma Adjustment, SWEPCO Payroll	<u><u>\$ (1,496,365)</u></u>
6	Composite Jurisdictional Factor ⁴	<u>39.16%</u>
7	Texas Retail Adjustment	\$ (585,976)
8	FICA Tax Effective Rate ⁵	<u>6.465327%</u>
9	Adjustment to Payroll Tax Expense	<u>\$ (37,885)</u>
10	Total Payroll Annualization Adjustment	<u><u>\$ (623,862)</u></u>

Note 1 See A (Cost of Service).xlsx, tab A-3.1 (SWEPCO Payroll), cell G65.

Note 2 CARD PR WP from CARD 4-5, CARD 5-5, CARD 8-1 Attachments 1.xlsx, cell D68.

Note 3 See A (Cost of Service).xlsx, tab A-3.1 (SWEPCO Payroll), cell F65.

Note 4 See A (Cost of Service).xlsx, tab A-1, cell D18

Note 5 See WP A-3.2 (FICA).xlsx, cells C18/C14.

SOUTHWESTERN ELECTRIC POWER COMPANY
 Cities Advocating Reasonable Deregulation AEPSC Payroll Expense Adjustment
 Docket No. 51415; Test Year End March 31, 2020

Line No.	Description	Amount
1	Test Year Payroll Expense ¹	\$ 38,821,330
2	SWEPCO Proposed Payroll Expense ²	<u>42,626,206</u>
3	CARD Pro Forma Adjustment, SWEPCO Payroll	<u>\$ (3,804,876)</u>
4	Composite Jurisdictional Factor ³	<u>39.16%</u>
5	Texas Retail Adjustment	<u>\$ (1,489,989)</u>

Note 1 See CARD_5-3_Attachment_3_(Summary_file_and_upload-proforma).xlsx, tab pivot, cell C70.

Note 2 See CARD_5-3_Attachment_3_(Summary_file_and_upload-proforma).xlsx, tab pivot, cell D70.

Note 3 See A (Cost of Service).xlsx, tab A-1, cell D18.

SOUTHWESTERN ELECTRIC POWER COMPANY
 Cities Advocating Reasonable Deregulation Annual Incentive Plan Adjustment
 Docket No. 51415; Test Year End March 31, 2020

Line No.	Description	Amount
1	SWEPCO Requested Annual Incentive Expense ¹	\$ 5,933,784
2	CARD Recommended Ratepayer Share of Annual Incentives ²	<u>3,746,384</u>
3	Adjustment for Earnings Based Funding Limit	\$ (2,187,400)
4	Composite Jurisdictional Factor ³	<u>39.16%</u>
5	Adjustment to share STI	\$ (856,586)
6	FICA Tax Effective Rate ⁴	<u>6.465327%</u>
7	Payroll Tax Adjustment	<u>\$ (55,381)</u>
8	Total Adjustment	<u><u>\$ (911,967)</u></u>

Note 1 See WP A-3.2 (SWEPCO ICP adjustment).xlsx, tab icp proforma, SUM(M26:M77).

Note 2 See CARD Incentive Adjustment from WP A-3.2 (SWEPCO ICP adjustment).xlsx, cell M79.

Note 3 Composite allocation factors from A (Cost of Service).xlsx, tab A-1, cell D18.

Note 4 See WP A-3.2 (FICA).xlsx, cell C18/C14.

SOUTHWESTERN ELECTRIC POWER COMPANY
 Cities Advocating Reasonable Deregulation Annual AEPSC Incentive Plan Adjustment
 Docket No. 51415; Test Year End March 31, 2020

Line No.	Description	Amount
1	AEPSC Target Incentives Less Direct Financial ¹	4,911,598
2	Less 50% for Financial Funding	<u>(2,455,799)</u>
3	CARD Recommended AEPSC Annual Incentives	2,455,799
4	Less SWEPCO Requested Annual Incentive Expense ²	<u>3,454,378</u>
5	Adjustment for Earnings Based Funding Limit	(998,579)
6	Composite Jurisdictional Factor ³	<u>39.16%</u>
7	Texas Retail Adjustment to share STI	<u><u>\$ (391,044)</u></u>

Note 1 From the Direct Testimony of Michael A. Baird, page 22, Annual Incentive Plan, 5th line.

Note 2 From BJF-18 (print entire workbook).xlsx, tab 2, cell K74.

Note 3 Composite allocation factors from A (Cost of Service).xlsx, tab A-1, cell D18.

SOUTHWESTERN ELECTRIC POWER COMPANY
 Cities Advocating Reasonable Deregulation Restrict Stock Units Adjustment
 Docket No. 51415; Test Year End March 31, 2020

Line No.	Description	Amount
1	SWEPSCO Test Year RSU Expense ¹	\$ 152,409
2	AEPSC Test Year RSU Expense ²	<u>873,584</u>
3	Requested long-term incentive expense	\$ 1,025,993
4	Adjustment to remove long term incentive expense	<u>\$ (1,025,993)</u>
5	Composite Jurisdictional Factor ³	<u>0.361623837</u>
6	Texas Jurisdictional Adjustment	<u>\$ (371,024)</u>

Note 1 from CARD_4-19_Attachment_1.xlsx, cell L51.

Note 2 from CARD 4-19 (2) d.

Note 3 from CARD_4-19_Attachment_1.xlsx, cell O51 / cell L51.

SOUTHWESTERN ELECTRIC POWER COMPANY
 Cities Advocating Reasonable Deregulation OPEB Expense
 Docket No. 51415; Test Year End March 31, 2020

Line No.	Description	Amount
1	Net SFAS 106 Benefit Costs, 2020 Actuarial Valuation Update ^{1,2}	\$ (7,753,163)
2	Payroll O&M Percentage ²	<u>69.71212%</u>
3	Projected SFAS 106 Post Retirement Costs in O&M ²	\$ (5,404,894)
4	Less Test Year Expense ^{2,3}	<u>(5,945,367)</u>
5	Corrected Adjustment to Test Year Expense ²	\$ 540,473
6	Less SWEPCO original adjustment A 3.11	<u>5,946,776</u>
7	CARD Adjustment to SWEPCO Requested SFAS 106 Expense	\$ (5,406,303)
8	Composite Jurisdictional Factor ⁴	<u>39.16%</u>
9	Texas Retail Adjustment, Account 926	<u><u>\$ (2,117,108)</u></u>

Note 1 See G-2.2 Attachment 1 (PBOP Expense).xlsx, cell F14 and CARD_4-41_Attachment_1_(WP_A-3.11).xlsx

Note 2 See CARD_4-41_Attachment_1_(WP_A-3.11).xlsx

Note 3 See WP A-3.11 (OPEBS SFAS 106).xlsx, cell F23.

Note 4 See A (Cost of Service).xlsx, tab A-1, cell D18.

SOUTHWESTERN ELECTRIC POWER COMPANY
 Cities Advocating Reasonable Deregulation Vegetation Managment Expense
 Docket No. 51415; Test Year End March 31, 2020

Line No.	Description	Amount
1	Test Year Vegetation Management Expense ¹	\$ 9,568,282
2	SWEPCO Requested Vegetation Management Expense ²	<u>14,568,282</u>
3	CARD Adjustment to Vegetation Management Expense, Account 593	<u><u>\$ (5,000,000)</u></u>

Note 1 From CARD 2-14, Attachment 1.

Note 2 From CARD 2-14, Attachment 1 plus Schedule A-3 Adjustment 20.

SOUTHWESTERN ELECTRIC POWER COMPANY
 Cities Advocating Reasonable Deregulation Property Insurance Expense
 Docket No. 51415; Test Year End March 31, 2020

Line No.	Description	Amount
1	Expected Annual Storm Loss ¹	\$ 799,700
2	Incremental Cost Request to Build Storm Reserve ²	<u>890,000</u>
3	Total Proposed Increase to Property Damage Expense	\$ 1,689,700
4	Adjustment to Remove the Increased Property Damage Expense, Account 924	<u><u>\$ (1,689,700)</u></u>

Note 1 From Schedule A-3, Adjustment 16, line 3.

Note 2 From Schedule A-3, Adjustment 16, line 4.

SOUTHWESTERN ELECTRIC POWER COMPANY
 Cities Advocating Reasonable Deregulation Refund of Unprotected EDIT
 Docket No. 51415; Test Year End March 31, 2020

Line No.	Description	SWEPCO Amount	Jurisdictional Factor	Texas Amount
1	Deprecation of Dolet Hills at Current Rates ¹	\$ 8,211,705	36.94341%	\$ 3,033,684
2	Requested Depreciation for Dolet Hills ²	<u>10,120,876</u>		<u>3,738,997</u>
3	Adjustment to Dolet Hills Depreciation Expense	<u>\$ (1,909,171)</u>		<u>\$ (705,313)</u>

Note 1 From D-4 (Depreciation Expense).xlsx, cell G135.

Note 2 From D-4 (Depreciation Expense).xlsx, cell K135, and WP B-1.5.17 (Dolet ADIT Off-Set).xlsx, tab Dolet Hills Estimated NBV, cells I21 and K21.

SOUTHWESTERN ELECTRIC POWER COMPANY
 Cities Advocating Reasonable Deregulation Refund of Unprotected EDIT
 Docket No. 51415; Test Year End March 31, 2020

Line No.	Description	SWEPCO Amount	Texas Amount
1	Non-Protected and Amortized Protected EDFIT ¹	\$ (82,311,412)	\$ (30,408,645)
2	Amortization Period	<u>4</u>	<u>4</u>
3	Annual Amortization	<u>\$ (20,577,853)</u>	<u>\$ (7,602,161)</u>

Note 1 From WP B-1.5.17 (Dolet ADIT Off-Set).xlsx, tabe Dolet Hills Estimated NBV, cells I19 and K19.

SOUTHWESTERN ELECTRIC POWER COMPANY
 Cities Advocating Reasonable Deregulation Depreciation Rate Adjustment
 Docket No. 51415; Test Year End March 31, 2020

Line No.	Description	CARD Recommended ¹	SWEPCO Amount ²	Adjustment
1	Depreciation Expense - Production	\$ 122,696,086	\$ 127,726,011	\$ (5,029,925)
2	Depreciation Expense - Transmission	43,377,049	47,949,610	(4,572,561)
3	Depreciation Expense - Distribution	55,763,186	64,202,401	(8,439,215)
4	Depreciation Expense - General	6,770,784	6,770,784	0
5	Amortization - Intangible Plant	22,714,099	22,714,099	0
6	Amortization - Texas Impairment	<u>(1,209,820)</u>	<u>(1,209,820)</u>	<u>0</u>
7	Totals	\$ 250,111,384	\$ 268,153,085	\$ (18,041,701)
8	Jurisdictional Factor ³	<u>38.47%</u>	<u>38.47%</u>	<u>38.47%</u>
9	Total Texas Retail Amount	<u>\$ 96,212,873</u>	<u>\$ 103,153,156</u>	<u>\$ (6,940,283)</u>

Note 1 From WP MG-2.11

Note 2 From A-3 (Proforma Adjustments).xlsx, tab A-3.4 (Depreciation Expense, Column (5)).

Note 3 See A (Cost of Service).xlsx, tab A-1, cell D22.

**SOAH DOCKET NO. 473-21-0538
PUC DOCKET NO. 51415**

**APPLICATION OF SOUTHWESTERN § BEFORE THE STATE OFFICE
ELECTRIC POWER COMPANY FOR § OF
AUTHORITY TO CHANGE RATES § ADMINISTRATIVE HEARINGS**

DIRECT TESTIMONY AND EXHIBITS

OF MARK E. GARRETT

EXHIBIT MG-3:

SUMMARY OF GARRETT GROUP LLC's INCENTIVE COMPENSATION

SURVEY OF THE 24 WESTERN STATES

Garrett Group Consulting, Inc.
Incentive Compensation Survey
of the 24 Western States
2018 Update

Results by State

Alaska 2011: (Regulatory Commission, Tyler Clark, Finance Manager, 907-276-6222) Incentive Compensation is not an issue in rate cases in Alaska. There is no relevant regulation or policy.

Alaska 2015: (Regulatory Commission, Tyler Clark, Chief Utility Financial Analyst, 907-276-6222) Incentive is not a contested issue yet in Alaska. There are no regulations, policies or cases addressing the issue.

Alaska 2018: (Regulatory Commission, Julie Vogler, Chief Utility Financial Analyst, 907-276-6222) The Commission in Alaska reviews requests to include incentive compensation in rates to determine if they are reasonable and if they benefit ratepayers. Short and long-term incentives receive the same treatment. The issue is handled on a case by case basis. In a recent Enstar Natural Gas case, U-16-066, the Commission allowed the Company's short and long-term incentive expense to be included in revenue requirement. The Final Order in U-16-066 (19), page 62, lines 6 through 14, states:

The record establishes that the overall cost of ENSTAR's incentive compensation is reasonable in a regulatory context. The scope and mechanics of the STIP and LTIP are clearly defined and described. And incentive compensation payments under the STIP and LTIP have been consistent and are expected to recur at levels comparable to the test year. ENSTAR's incentive compensation plans benefit ratepayers by setting and holding employees to goals that directly relate to customer service and cost controls, and by attracting and retaining highly qualified employees to provide safe and reliable service. We find that inclusion of the incentive compensation amounts as an expense in ENSTAR's revenue requirement is reasonable.

The Enstar case is the first adjudicated case since the last survey results were provided in 2015, so there are no other recent orders that set forth a treatment of the issue.

Arizona: (Corporation Commission, Darron Carlson, 602-542-0834) Arizona deals with incentive compensation plans on a case by case basis. They generally do not allow the costs for these programs to be included in rate base. They have at times allowed 50% of the cost of a particularly good plan to be included in rates.

Arizona 2009: (Corporation Commission, Darron Carlson, 602-542-0834) Arizona deals with incentive compensation plans on a case by case basis. It first compares overall compensation to the state norm, then asks if the cost are prudent and reasonable. They lean toward disallowing programs which benefit only the shareholder even if total compensation is comparable to the state norm.

Arizona 2011: (Corporation Commission, Darron Carlson, 602-542-0834) Still examining case by case, the Arizona Staff's position is that if the company fails to demonstrate that an incentive compensation plan is tied to operational performance issues it is considered unnecessary for the provision of service. Staff feels shareholders should pay for plans tied to financial measures such as earning per share. Most cases settle here and there are no orders on point.

Arizona 2015: (Corporation Commission, Darron Carlson, Manager, Financial and Regulatory Analysis Section, Utility Division, 602-542-0834) Incentive programs are still considered case by case. Evaluation centers around the criteria of benefit to customers. This treatment tends to make long-term programs harder to justify, but the same criteria are used to evaluate all plans including those for executives. This treatment is set forth in the most recent Epcor Water rate case (Docket No. WS-01303A-14-0010). The current treatment represents a somewhat more liberalized approach compared to Arizona's former position of excluding all incentive compensation from rates.

Arizona 2017: A review of Commission decisions in cases since the 2001 Decision 64172 is provided in the testimony of staff witness Ralph C. Smith in Docket No. E-0134SA-16-0036 (pp.81-89). This review demonstrates that the Commission recognizes that financial goals primarily benefit the shareholder and operational goal can benefit the customer. The Commission accordingly shares the cost of short-term incentives equally between ratepayers and the shareholders. In Decision No. 71914 (September 30, 2010), in UNS Electric, Inc. rate case, Docket No. E-04204A-09-0206, the Commission stated at page 28:

We believe that the Staff and RUCO recommendations, to require a 50/50 sharing of incentive compensation costs, provide a reasonable balancing of the interests between ratepayers and shareholders. The equal sharing of such costs recognizes that the program is comprised of elements that relate to the parent company's financial performance and cost containment goals, matters that primarily benefit shareholders, while at the same time recognizing that a portion of the program's incentive compensation is based on meeting customer service goals. This offers the opportunity for the Company's customers to benefit from improved performance in that area.

Arizona Incentive Compensation Treatment by Case

Short-Term Incentives*

Year	Company	Docket/Decision Number	Lit./Stlmt.	Outcome
2001	SWG	G-01551A-00-0309 / 64172 (p. 13)	Litigated	50:50 Sharing
2007	APS	E-013451-05-0816 / 69663 (p. 37)	Litigated	Allowed**
2008	APS	E-01345A-08-0172	Settlement	50:50 Sharing
2011	APS	E-01345A-11-0224	Settlement	50:50 Sharing
2007	UNS	G-04204A-06-0463 / 70011 (p. 27)	Litigated	50:50 Sharing
2008	UNS	E-04204A-06-0783 / 70360 (p. 21)	Litigated	50:50 Sharing
2006	SWG	G-01551A-04-0876 / 68487 (p. 18)	Litigated	50:50 Sharing

2008	SWG	G-01551A-07-0504 / 70665 (p. 16)	Litigated	50:50 Sharing
2010	UNS	G-04204A-08-0571 / 71623 (pp. 30-31)	Litigated	50:50 Sharing
2010	UNS	E-04204A-09-0206 / 71914 (pp. 28-29)	Litigated	50:50 Sharing

* See Staff witness Smith in APS 2016 Rate Case E-0134SA-16-0036 pp. 81-89.

** The Commission accepted Staff's position: "Staff did not oppose inclusion of the TY variable incentive expense in cost of service, noting that although corporate earnings serve as a threshold or precondition to the payout, the TY level of expense is tied primarily to performance measures that directly benefit APS customer." (page 37)

Arizona 2018: (Corporation Commission, Darron Carlson, Public Utilities Analyst Manager, Revenue Requirements and Audits, 602-542-0834) There have been no changes to the treatment of incentives in Arizona. The issue is still dealt with on a case by case basis centered on benefit to the customer. The treatment is the same for short and long-term plans as well as executive incentives. There are no new orders setting forth the treatment.

Arkansas: (PSC, Alice Wright, 501-682-2051) In the current Entergy Arkansas Rate Case Docket No. 06-101-U, staff witness Jeff Hilton recommends excluding 50% of the portion of plans tied to financial performance, which means disallowing half of the executive's plan. See attached direct and surrebuttal testimony.

Arkansas 2009: (PSC, Jeff Hilton, Manager, Audit Section, General Staff, APSC 501-682-2051) The treatment of incentive compensation has changed recently in Arkansas. The traditional treatment had been to allow in rates those plans based on operational goals (which were seen as benefitting ratepayers), and sharing 50:50 between shareholders and ratepayers the costs of programs which included operational and financial goals (and thereby benefitting both ratepayers and shareholders). The current change is that now, executive plans which are based solely on increasing corporate stock value are seen as benefitting only the shareholders and are excluded from rates. A further refinement of Commission policy is to allow, for any given plan, 50% of the *portion* of that plan which has value for both ratepayers and shareholders. This new treatment is documented in the Entergy order 06-101-U, Order 10, and in the settlement adopted in the latest OG&E case 08-103-U. One reason for the change to exclude these executive plans was that while they were being subsidized by ratepayers they were growing astronomically.

Arkansas 2011: (PSC, Jeff Hilton, Manager, Audit Section, General Staff, APSC 501-682-2051) The Arkansas Commission has uniformly maintained its treatment based on the 2006 Entergy case (06-101-U) cited above. Long-term plans, typically based on stock price, are excluded from rates 100%. Short-term incentive plans are evaluated to determine if they are based on financial or operational measures. Operational-based plans are allowed. 50% of plans containing financial measures are disallowed. Any plans based solely on the discretion of the company are seen as having no direct benefit to ratepayers and are disallowed 100%. Settlements in recent cases have upheld this treatment.

Arkansas 2015: (PSC, Jeff Hilton, Director of Revenue Requirements, 501-682-2051) Commission rulings on Incentive Compensation have remained generally consistent, excluding 100% of long-term plans and 50% of the portion of short-term plans that are financially based. This treatment has been qualified in recent cases based on differing plan structures. In the most recent contested Entergy rate case (Docket No. 13-028-U), 50% of all short-term incentive compensation was excluded because the plans

included a financially-based multiplier. The criteria of distinguishing between financial and operational measures that results in different treatment for short and long-term plans is used to evaluate all plans including those for executives. Arkansas' treatment of this issue is considered case by case and is based on prior Commission orders, not legislation. While the Commissioners' position has remained consistent, Staff's recommendation in the last several cases, including 13-028-U and two currently under review, has shifted. Staff has recently considered that any incentive compensation plan which they find is prudent and is necessary for the provision of utility service to ratepayers should be included in rates. Based on these criteria, Staff has recommended no disallowance in these three cases, a position which the Commission did not adopt in the 13-028-U Entergy case.

Arkansas 2018: (PSC, Jeff Hilton, Director of Revenue Requirements, 501-682-5185) The Arkansas Commission continues to follow the precedent of its previous orders and generally disallows 50% of financially based Short-term incentive plans and 100% of Long-term plans (which include the executive plans). There is some flexibility for considering a utility's particular situation on a case by case basis, but the two larger utilities in Arkansas, Entergy and CenterPoint, are both on formula rate plans and the 50%/100% disallowance treatment is incorporated in those FRPs, based on their most recent respective rate cases, 15-015-U and 15-098-U, in which the Commission specifically expressed this preference.¹

California: (PUC, Pamela Thompson, Div. of Ratepayer Advocacy, 415-703-5581, Mark Pocta, 415-703-2871) In CPUC Decision 00-02-046 the Commission established that utilities could recover 50% of the regular employee's incentive compensation costs from rates. Mark Pocta says they advocate for some type of sharing arrangement and points out that PGE has a 50/50 arrangement for both executive and employee plans, while Southern California Edison passes 50% of its executive plan and all of its employee plan to ratepayers.

California 2009: (PUC, Mark Pocta, Division of Ratepayer Advocacy, 415-703-5581) In California, incentive compensation funding is always an issue and is typically litigated. In California's latest litigated rate case, Southern California Edison (Application #: 07-11-011, Decision #: 09-03-025) the DRA argued for disallowing of incentive compensation in rates citing vague performance measure and the fact that all the plans were, at least in part, based on the Company's financial performance. The Commission, however, decided that the non-executive plans (at Edison there are plans for all employees) and 50% of the short-term executive plans will be funded in rates, while only the long-term executive stock option plans will be disallowed. In 2000, in the PGE case (CPUC Decision 00-02-046), the Commission allocated a 50:50 sharing of all the management incentive compensation programs between ratepayers and shareholders.

California 2011: (PUC, Matthew Tisdale (CPUC), Pamela Thompson, Mark Pocta, Division of Ratepayer Advocacy, 415-703-5581) No response from California in 2011.

California 2015: (PUC, Richard Rauschmeier, Financial Examiner, DRA - Division of Water and Audits, 415-703-2732) The Commission considers incentive compensation on a case by case basis. Plans are evaluated in the context of an overall reasonableness standard. The Commission has also established

¹ In Docket No. 15-015-U, Order No.18, pp. 18-20, the Commission reversed a settlement treatment which disallowed only 25% of financially-based Short-term incentives, imposing instead a 50% disallowance.

precedence for evaluating plans based on who benefits from the plans' goals, ratepayer or shareholders. This approach quite often results in different outcomes for short-term and long-term plans. In determining overall reasonableness, the Commission also considers many other criteria such as comparisons with similarly sized utilities, benchmarking to related industry, internal historical trends and overall compensation. In a recent case, A.10-07-007, staff recommended that, "customer funding should be limited to the portion of the incentive plan payments that are aligned with operational objective that provide customer benefits. This means that 70% of AIP be funded by shareholders, and 30% be funded by ratepayers." In the settlement, the Commission disallowed 50% of the plan's expense. One change that may impact consideration of incentives going forward is the Commission's renewed focus on safety since the San Bruno pipeline explosion. The Commission is establishing metrics for observing historical trends and industry comparisons, and is emphasizing neutral third-party benchmarking.

California 2018: (CPUC, Richard Rauschmeier, Financial Examiner, Public Advocate's Office, 415-703-2732) The CPUC examines utility company requests to include incentive compensation in rates on a case by case basis, but the criteria are well established. Generally, incentive compensation expense can be charged to ratepayers only to the extent it is aligned with ratepayer interests. Typically, this treatment results in disallowance of the portion of short-term incentives tied to financial performance². The Commission's consistent practice is to reject recovery of long-term incentives, "because, LTI does not align executives' interests with ratepayer interests."³ Since the 2010 San Bruno pipeline explosion (and other events including the Aliso Canyon Leak, and the Witch, Guejito and Rice Wildfires which were found to be caused by utilities), legislative and regulatory interest in utility safety has intensified⁴. Consequently, the treatment of incentives is increasingly framed by asking whether the incentives are safety-focused or earnings-focused.

Colorado: (PUC, Rob Trokey, 303-894-2121) Colorado has no regulatory or statutory rules governing incentive compensation and considers it on a case by case basis. In the 2006 PSC Colorado (electric utility) Rate Case 06-S-234-EG, the Office of Consumer Council argued for removing the costs of the portion of the plan not benefiting ratepayers. That case settled without the Commission ruling. In the current gas utility rate case staff is removing incentive compensation from rate base.

Colorado 2009: (PUC, Karl Kunzie, Financial Analyst: Economics Section, 303-894-2882, P.B. Scheckter, Office of Consumer Counsel (OCC), 303-894-2124) Colorado has no rules or statutes and, due to black-box settlements, no recent orders on point. Historically, the policy of the OCC has been to disallow plans tied to goals such as price per share, and allow in rates those plans tied to quality of service and goals that benefit ratepayers. The PUC has tended not to oppose the company's historic test year payouts. However, in the current Public Service Company of Colorado (Xcel Energy) rate case, Staff has argued to exclude all types of incentive compensation from rates. This treatment holds that incentive compensation, in general, benefits only the shareholder, that it is discretionary and sometimes is not be paid out, and that all of it should be paid for by the shareholders. The goals related to ratepayer benefit

² Examples of this treatment: Decision 15-11-021, Decision 12-11-051 and Decision 14-08-032.

³ Decision 15-11-021 at 262

⁴ CPUC's view of incentives in terms of promoting a positive or negative safety culture is discussed at length in Decision 16-06-054 (San Diego Gas & Electric). Also see R.15-09-010, D.11-06-017 and Public Utilities Code Section 706.

should be considered part of the job and compensated for by regular wage and salary. In this treatment, if total compensation is then non-competitive the regular, non-optional component of compensation should be raised.

Colorado 2011: (PUC, Karl Kunzie, Financial Analyst: Economics Section, 303-894-2882) Colorado staff has made the decision not to seek to eliminate all incentive compensation (rolling compensation for goals benefitting ratepayers into regular salaries). All executive incentives are still excluded from rates and no longer sought in company filings. Regular employee programs are judged on their benefit to ratepayers verses stockholders. Plans with metrics for goals benefitting ratepayers but dependent on an earnings per share trigger are considered to benefit shareholders and opposed by staff. Staff's approach is set forth most recently, in 10AL-963G by staff witness Kahl. The settlement in that case removed the dollar amount opposed by Kahl without specifically stating the rationale.

Colorado 2015: (PUC, Karl Kunzie, Financial Analyst: Economics Section, 303-894-2882) Colorado still excludes long-term executive incentive compensation from rates. However, with respect to annual incentive pay (AIP), Colorado's treatment has changed significantly. In the most recent rate case for Public Service Company of Colorado, staff recommended the Commission, "limit reimbursement of incentive pay to no more than 15 percent of employee base salary." In this Proceeding No. 14AL-0660E / Order C15-0292, the Settling Parties agreed to reduced the revenue requirement by a dollar amount without agreeing to any specific adjustments. However, on the issue of AIP, the Settlement Agreement included the statement, "the Settling Parties agree AIP incentive payment recovery in the 2017 Rate Case will be capped at 15% of an employee's salary." This treatment does not evaluate incentive compensation plans based on some criteria such as their prudence, or which stakeholder group benefits from the goals of a plan. With respect to choosing a straight percentage of salary, Staff's witness, Fiona Sigalla, noted in her testimony of November 7, 2014: "Annual incentive plan payments to employees exceed 10 percent of salary for most workers and tops 100 percent of salary for some executives." "In 2014, the top 20 highest paid Xcel Energy executives received AIP payments that averaged over 100 percent of salary. Limiting reimbursement of incentive pay to 15 percent of base pay would mostly impact these higher paid employees." "Fifty-six percent of the impact for 2013 affects reimbursement of incentive pay for Company executives." This treatment is expected to continue at least through the term of the 2017 PSCo rate case.

Colorado 2018: (PUC, Karl Kunzie, Financial Analyst: Economics Section, 303-894-2882) There have been no changes to the treatment of incentive compensation in Colorado since the last update to the survey. Long-term incentives are not allowed recovery in rates. Recovery of short-term plans is limited to 15% of base salary without evaluating plan goals. This treatment was followed in the PSCo Gas rate case in 2018, Proceeding No. 17AL-0363G. No change to this treatment is anticipated.

Hawaii 2011: (PUC, Steven J. Iha, Chief Auditor, 808-586-2020) Hawaii does not allow incentive compensation to be included in rates. This policy was set forth in Docket No. 6531, in the October 17, 1991 Order No. 11317. Prior Dockets in which the Commission disallowed incentive compensation include No. 3216, No. 4215, No. 4588 and No. 5114. In 6531 the Commission agreed that bonus awards tied to company income and earnings benefit stockholders, not ratepayers. The Commission further states, "...we believe that a utility employee, especially at the executive level, should perform at an optimum level without additional compensation. Ratepayers should not be burdened with additional

costs for expected levels of service." In the 1991 case, the Commission also excluded the negative deferred income taxes associated with incentive plans which were disallowed from the deferred income taxes that are deducted from the rate base.

Hawaii 2015: (PUC, Steven J. Iha, Chief Auditor, 808-586-2020) Hawaii's general policy toward incentive compensation has not changed. Incentive compensation of all types is excluded from rates. The Commission upholds the position stated in Docket No. 6531 that incentives tied to company income and earnings benefit stockholders, not ratepayers. The Commission further stated, "...we believe that a utility employee, especially at the executive level, should perform at an optimum level without additional compensation. Ratepayers should not be burdened with additional costs for expected levels of service." Utilities in Hawaii no longer petition to have incentive compensation expense included in rates.

Hawaii 2018: (PUC, Jan K. Mulvey, Chief Auditor, 808-586-2020) Hawaii's longstanding policy to exclude all incentive compensation expense from rates remains firmly in place. The Commission upholds the position stated in Docket No. 6531 that incentives tied to company income and earnings benefit stockholders, not ratepayers. The Commission stated at page 59, "We recognize that incentives encourage cost reductions in some instances. However, we believe that a utility employee, especially at the executive level, should perform at an optimum level without additional compensation. Ratepayers should not be burdened with additional costs for expected levels of service." This treatment is not challenged by the utilities.

Idaho: (PUC, Terri Carlock, Accounting Section Supervisor, 208-334-0356) As general policy, Idaho does not allow into rates the costs associated with profits and earnings performance, but does allow a portion of plans that benefit the ratepayer through improved customer service, etc. Executive's incentive compensation plans are evaluated using the same criteria and are not often allowed. See Idaho Power Company Rate Case IPC-E-05-28 Corrected Motion for Approval of Stipulation 3/1/06, 6e, p. 4; Idaho Power Company IPC-05-28 Order No. 30035, p. 4/10.

Idaho 2009: (PUC, Terri Carlock, Accounting Section Supervisor, 208-334-0356) The Commission's basic policy for evaluating incentive compensation plans involves determining who benefits, the customer or the company. This treatment has been refined (in the recent Idaho Power Company general rate case) for plans which benefit the customer but require a financial trigger (e.g. must meet a certain dividend level) to be paid. For these plans the Commission reduced the percentage allowed in rates. The Commission also now does not include any executive compensation in rates. The Commission's focus on customer benefit is reflected in the direct testimony of Staff witness, Leckie, and in the final order for the recent IPC General Rate Case IPC-E-08-10. For earlier examples of the basic policy, see Idaho Power Company Rate Case IPC-E-05-28 Corrected Motion for Approval of Stipulation 3/1/06, 6e, p. 4; Idaho Power Company IPC-05-28 Order No. 30035, p. 4/10 (attached '07).

Idaho 2011: (PUC, Terri Carlock, Utility Division Deputy Administrator, Accounting Section Supervisor, 208-334-0356) Treatment of incentive compensation remains unchanged in Idaho. Ms. Carlock summarizes the Idaho Public Utility Commission treatment as follows, "For Idaho utility companies, the short answer is that incentives that are based on targets that provide customer benefits, i.e. customer service, reliability, O&M budgets, safety etc., are included in rates. Incentives that are based on targets that provide shareholder value are excluded." Executive plans typically fall into the second category and are excluded. More specifically: Idaho Power has an Executive Incentive Plan that is

separate from the Annual Employee Incentive Plan, and it is excluded from rates. Avista has one plan Incentive Plan that has different targets based on different criteria. Executives participate in this plan, but because executives have a different set of targets, only the targets associated with customer service and reliability are included in rates. PacifiCorp Incentive Plan, each individual employee has their own set of goals and targets in order to achieve an incentive payment, and those targets are different for executives. Executive incentives have not requested for rate recovery.

Idaho 2015: (PUC, Terri Carlock, Utility Division Deputy Administrator, Accounting Section Supervisor, 208-334-0356) Idaho's treatment of incentives has not changed - most is disallowed. To be included in rates a plan must benefit ratepayers. Plans based on measures which benefit shareholders, such as increased earnings, are excluded. This treatment is the same for all plans including those for executives. There are no recent orders on point, but the three rate case scheduled this year are expected to reflect this treatment.

Idaho 2018: (PUC, Terri Carlock, Utility Division Administrator, Accounting Section Supervisor, 208-334-0356) There has been no change to the treatment of incentives in Idaho. The Commission allows in rates those incentives that benefit customers and exclude those based on financial measures that benefit shareholders. This treatment is the same for incentives at all levels, but executive plans receive closer scrutiny as it is often harder to find customer benefit in these plans. There are no recent orders on point and no changes are anticipated in the near future.

Iowa: (Utilities Board, Wes Birchman, 515-281-5979) Incentive compensation is not an issue here as they do not do many rate cases.

Iowa 2009: (Utilities Board, Wes Birchman, 515-281-5979, Dan Fritz, 515-281-5451) Mid-America has an incentive compensation plan but hasn't filed a rate case in many years. For the state's other utilities, it has been a long time since they have filed a rate case or had a rate increase. The standing treatment is to look at incentive compensation plans on a case by case basis and evaluate whether or not they are reasonable and prudently incurred.

Iowa 2011: (Utilities Board, Dan Fritz, 515-725-7316) Both of the investor owned utilities in Iowa are under rate freezes until 2013 and 2014. There has been no change in the treatment of utility incentive compensation.

Iowa 2015: (Utilities Board, Dan Fritz, 515-725-7316) Incentive Compensation has not been an issue in Iowa. There are no specific treatments in place and the Commission will review the merits and prudence of a proposed plan on a case by case basis. There are no recent orders on point, and no treatment changes are anticipated.

Iowa 2018: (Utilities Board, Dan Fritz, 515-725-7316) There have been no changes in the treatment of Incentive Compensation. There are no specific treatments in place and the issues is handled on a case by case basis. There are no recent orders on point.

Kansas: (Corporation Commission, Utilities Div., Larry Holloway, Chief of Engineering Operations, 785-271-3222) On a case by case basis staff opposes plans without ratepayer benefit or are lacking objective measures.

Kansas 2009: (Corporation Commission, Utilities Division, Bob Glass, Chief of Economic Section, 785-271-3175) The Commission views incentive compensation plans that are based solely on financial performance as benefitting only the shareholders and not something that belongs in rates. In the last 5 to 10 years the Commission has not seen incentive compensation as a major issue and tends not to challenge plans that are reasonable by industry standards as long as they are based on a multidimensional set of criteria involving both reliability and financial goals. In Kansas, the Commission also funds the Citizens Utility Rate Board (CURB), an advocacy group for the residential and commercial ratepayers. CURB argues that any portion of a plan that relates to financial measures should be disallowed.

Kansas 2011: (Corporation Commission, Utilities Division, Jeff McClanahan, Chief of Accounting and Financial Analysis, 785-271-3212) The Kansas Commission recently has changed its stance on incentive compensation. In the litigated 2010 KCP&L rate case (10-KCPE-415-RTS) the Commission stated that relying on peer group statistics "can result in a continuing upward spiral [instead] the Commission must examine the elements of incentive packages, and the behavior they incent". For executive incentive programs, the Commission disallowed 100% of payments based on purely financial measures and 50% for plans using a balance of financial and operational measures. The Commission allowed in rates the non-executive annual incentive program after Staff found that KCP&L had modified the measures used in this plan and, "eliminated all focus on profitability or earning [which might incent employee behavior] detrimental to customers."

Kansas 2015: (Corporation Commission, Utilities Division, Justin Grady, Chief of Accounting and Financial Analysis, 785-271-3164) The Kansas Corporation Commission continues to rely on the treatment it established in the litigated 2010 KCPL rate case (10KCPE-415-RTS) and followed in the 2012 case, 12-KCPE-764-RTS. For officer level incentives, plans are evaluated to determine whether the objectives of the plan are geared to improve the company's financial results or to improve operational objectives. The financially-based portion is borne by the shareholders and the portion supporting operational goals is allowed in rates. The exception to this evaluation process are any time-based restricted stock plans which vest solely on the passage of time. Such plans are seen as being neutral and therefore split 50:50 between shareholders and ratepayers. Non-officer incentive compensation plans for workers are allowed in rates. This treatment is becoming established as the Commission's general policy⁵ and has guided Staff's position on these issues in both of its current rate cases for KCPL (15-KCPE-116-RTS) and Westar (15-WSEE-115-RTS). However, the consumer advocacy branch, Citizens' Utility Ratepayer Board (CURB) has consistently recommended the more aggressive position of applying the same financial/operational criteria to non-officer plans as well. In the current KCPL rate case the company has voluntarily excluded 50% of the restricted stock plans, 100% of the performance-based plans, 50% of the short-term plans which are based on an earnings-per-share qualifier. The Company has also removed the earnings-per-share portion of their Value Rewards Plan which is open to all employees. This was seen as an attempt to find the middle ground between staff's position and that of CURB. In this case CURB did not make an adjustment challenging the company's proposed recovery.

⁵ In the 2012 KCPL rate case (12-KCPE-764-RTS) this treatment resulted in a 50:50 split of the short-term plan. For the long-term incentives, the Commission excluded 50% of the time-based restricted stock portion of the plan, and 100% of the portion based on stockholder return.

Kansas 2018: (Corporation Commission, Utilities Division, Kristina Luke-Fry, Managing Auditor, 785-271-3171) Kansas still allows all employee-level incentives in rates. For management and executive incentives, the Commission only allows in rates those incentives related to safety and other operational objectives, and excludes incentives related to financial measures such as earnings per share. This treatment is based on prior orders, especially 10KCPE-415-RTS and 12-KCPE-764-RTS. This treatment has the result of excluding the majority of executive incentives due to the fact that they are usually tied to company earnings. There are no recent orders on point, and no changes in treatment are anticipated.

Louisiana 2009: (PSC, Brian McManus, Economist, Division of Economics and Rates Analysis, 225-342-2720; Bill Barta, Henderson Ridge consulting, 770-205-8828) Louisiana has traditionally held that the incentive compensation plan for upper level management and officers are excluded from rates, while those of lower level of managers and employees are included in rates. The criteria originally used to arrive at this treatment considered whether the goals of each plan more directly benefitted ratepayers or shareholders. Recently, an ALJ's report in the Entergy Louisiana Formula Rate Plan 2006 (Docket # U - 20925, 2006 Evaluation Period) has recommended excluding all stock option plans for all levels. The Commission has also recently chastised Entergy for excessive bonuses.

Louisiana 2011: (PSC, Brian McManus, Economist, Division of Economics and Rates Analysis, 225-342-2720) The Louisiana Commission does not allow Executive Bonuses to be recovered from ratepayers. This is especially true for the larger utilities. For incentive awards to employees that are not Executives, the Commission may allow recovery. For some of the smaller utilities the Commission may allow bonuses to management if the whole compensation package is reasonable. There has not been any docketed proceeding since 2006.

Louisiana 2015: (PSC, Brian McManus, Economist, Division of Economics and Rates Analysis, 225-342-2720) No response from Louisiana at this time.

Louisiana 2018: (PSC, Robin Pendergrass, Audit Director, (225-342-1457) The treatment of incentive compensation in Louisiana has not changed. The LPSC does not allow Executive incentive compensation plans to be recovered from ratepayers. Lower level management and employee incentive awards may be included, assuming they are reasonable. To determine reasonableness, the Commission looks at the amount of the incentive in relation to 1) the size of the company 2) the job duties of the employee and 3) the average hours worked during the test year. The Commission also looks at who benefits, ratepayers or shareholders. This is a general auditing policy utilized in all LPSC rate reviews. Recent dockets which followed this treatment, where disallowances were made using these criteria, include Dockets U-34667 and U-34669, which are the 2017 annual RSP filings for CenterPoint Arkla and CenterPoint Entex, respectively. Both dockets show disallowances for competitive and incentive pay and other executive compensation.

Minnesota: (PUC, Louis Sickmann, Financial Analyst, 651-201-2243) Minnesota looks at incentive packages on a case by case basis. Since the 1991 decision to deny incentive compensation costs in the

ESP Electric Rate Case, the Commission has begun to allow inclusion of employee plans. It capped these plans (at 15% of base salary) out of a concern that larger percentages tied the employees too closely to shareholders' interests. Current caps are at 25% of base salaries. The portions of these plans that are allowed into rates are tracked and must be returned to ratepayers if they are not paid to employees (as has been the case when earnings per share targets were not met). Executive plans are largely not allowed. See General Rate Case E002/GR/05/1428, September 1, 2006.

Minnesota 2009: (PUC, Louis Sickmann, Financial Analyst, 651-201-2243) Minnesota's treatment of incentive compensation has changed recently. One influence that has allowed this change is that Minnesota's utilities have move away from asking the Commission to include in rates those plans that are tied strictly to company earnings. Currently plans which are based on earnings and don't include goals that benefit the ratepayer are limited to long-term management plans which are excluded from rates. The two new parts of Minnesota's treatment of plans that do benefit ratepayers are, first, to cap those plans at 25% of base salary and , second, to refund all portions of the plan which are not actually paid out to employees.

Minnesota 2011: (PUC, Jerry Dasinger, Financial Analyst, 651-201-2235) Minnesota continues to distinguish between incentive plans tied to financial triggers (such as a threshold ROE), and plans tied to criteria benefitting the ratepayer. Plans based on goals which benefit ratepayers are allowed in rates, but their costs are still capped at 25% of base salaries. This cap is being challenged by arguments to lower it to 15%. This general policy is demonstrated in recent orders in the Minnesota Power and Ottertail rate cases: E002/GR-09-1151 and E002/GR-10-239 respectively.

Minnesota 2015: (PUC, Sundra Bender, Financial Analyst, 651-201-2247) Minnesota continues to distinguish between incentive plans tied to financial triggers (such as a threshold ROE) and plans tied to criteria benefitting the ratepayer. Plans based on goals which benefit ratepayers are generally allowed in rates, but their costs are frequently capped at a percentage of base salaries such as 15% or 25% (the percentage can vary from case to case). Utilities are usually required to return to ratepayers any portion of incentive pay that was allowed into rates and is not subsequently paid out to employees. Executive and long-term IC measures are frequently more closely aligned with shareholder interests and thus are not usually allowed in rates. An example of the Commission's treatment is set forth in General Rate Case G-008/GR-13-316, June 9, 2014 Findings of Fact, Conclusions, and Order at pages 13-17 and page 58.

Minnesota 2018: (PUC, Sundra Bender, Financial Analyst, 651-201-2247) Minnesota continues to determine allowable incentive compensation on a case by case basis. Annual incentive plan compensation is usually allowed in rates, but the costs are frequently capped at a percentage of base salaries, for example: 15%, 20%, or 25% (the percentage can vary from case to case). Utilities are usually required to return to ratepayers any portion of incentive pay that was allowed into rates and is not subsequently paid out to employees. Long-term incentive compensation measures are not usually allowed in rates. A recent case example is the Minnesota Power General Rate Case E-015/GR-16-664, March 12, 2018 Findings of Fact, Conclusions, and Order at pages 31-34 and 110.

Missouri: (PSC, Utility Services Div., Bob Schallenberg, 573-751-7162) On a case by case basis, Missouri includes plans that benefit consumers and otherwise disallows incentive compensation plans. The same criteria are used for executive plan – few are allowed. See recent Kansas City Power and Light and Empire Electric District orders on the Commission's website.

Missouri 2009: (PSC, Utility Services Div., Bob Schallenberg, Manager, 573-751-7162) In Missouri, value to the customer is the general policy that informs their treatment of incentive compensation plans. A plan's goals must be beneficial to the customer or the plan is not allowed in rates. Plans based on rate of return, for example, are not allowed. This treatment also applies to executive plans which generally have less chance of being allowed in rates. See Ameren ER 2009-0318.

Missouri 2011: (PSC, Utility Services Div., Bob Schallenberg, Manager, 573-751-7162) Missouri's treatment remains consistent in disallowing incentives tied to goals benefitting primarily the stockholders (e.g. tied to earnings per share) while allowing plans with customer-specific goals (e.g. safety). However, even these plans must be reasonable to be allowed. For example, in the last Missouri American rate case (WR-2010-0131), not only were plans based on financial goals disallowed, but incentive payments based on customer satisfaction were disallowed due to the unreasonably small sample size used to establish a positive rating (a phone survey of 927 of roughly 450,000 customers). The Commission also removed incentive payments tied to lobbying and charitable activity. In the most recent case processed, the Ameren UE rate case, the company didn't seek even short-term incentive compensation tied to earnings demonstrating that staff's practice is becoming accepted by the companies. In that case, the Commission did allow some payments related to service, but only the amounts actually paid, not those accrued. All incentive compensation adjustment were made not only to expense charges, but to construction charges as well.

Missouri 2015: (PSC, Utility Services Div., Bob Schallenberg, Manager, 573-751-7162) Incentives are addressed on a case by case basis. Plans are analyzed to determine who benefits. Plans that can show a direct benefit to customers (and that are found to be prudent) are allowed in rates. Plans that benefit shareholders are excluded. This treatment does not typically result in a different outcome (being allowed or disallowed in rates) for short-term verses long-term plans. Executive plans are less often allowed in rates due to ties to rate of return. There are no recent orders which demonstrate this treatment.

Missouri 2018: (PSC, Commission Staff Div., Mark Oligschlaeger, Manager, Auditing Department, 573-751-7443) Missouri's treatment for incentives, generally, is to allow rate recovery for those plans with goals that, if achieved, would lead to improved or more economical service to customers and with the goals known to employees in advance so as to be a real motivational tool. Incentives tied to financial goals such as earnings per share, net income or stock price growth are not allowed. These criteria are used to evaluate all incentive plans, short or long-term, as well as those for executives. This treatment is not proscribed by statute or rule, but has been the longstanding policy of the Commission, and was followed in the recent Spire Missouri rate cases, Case Nos. GR-2017-0215 and GR-2017-0216. There have been no recent changes to this treatment, and none are anticipated in the near future.

Montana: (PSC, Eric Eck, Chief, Revenue Requirement Bureau, 406-444-6183) Montana has no rule or policy concerning incentive compensation and no recent cases on point. They deal with the issue on a case by case basis.

Montana 2009: (PSC, Eric Eck, Chief, Revenue Requirement Bureau, 406-444-6183) Montana has no rules or recent cases dealing with incentive compensation.

Montana 2011: (PSC, Eric Eck, Chief, Revenue Requirement Bureau, 406-444-6183) Montana has no changes in its treatment of incentive compensation. It has no specific treatment directive and considers the issue on a case by case basis. In a recent NorthWestern Energy rate case, as part of a stipulation agreement, the company took a portion of its incentive compensation out of rates, but reserved the right to propose that it be included in a later filing.

Montana 2015: (PSC, Eric Eck, Chief, Revenue Requirement Bureau, 406-444-6183) Due to the low volume of litigated cases in the past 10 to 15 years in Montana, incentive compensation has not been an important issue before the Commission. This Commission is focused more on significant investment in infrastructure, such as the ongoing distribution project by NorthWestern. Incentive compensation is considered the responsibility of the utility's Board of Directors and is generally not challenged. However, the Commission tends to become more concerned by incentive plans that are tilted toward financial performance instead of operational goals. Short and long-term plans are handled similarly, and the Commission prefers plans that are broadly available to employees.

Montana 2018: (PSC, Gary Duncan, Revenue Requirements and Audits, 406-444-6189) Incentive compensation has not been a contested issue in the three rate cases in Montana since the 2015 survey. All utility compensation, including incentives, is recovered through rates in Montana.

Nebraska: (Public Service Commission, Laura Demman, Director and Legal Counsel, Natural Gas Department, NPSC, 402-471-3101) Nebraska is unique in that all of its electric demand is supplied by consumer-owned power districts, cooperatives, and municipalities. The Natural Gas Department of the NPSC regulates the rates and service quality of investor-owned natural gas public utilities pursuant to the state's Natural Gas Regulation Act passed in 2003. Nebraska does not have rules regarding incentive compensation and considers the issue on a case by case basis. In a 2007 rate case, NG-0041, with Aquila (later acquired by Black Hills), the Commission allowed in rates only the actual amounts paid, an adjustment to provide for a known and measurable expense. This order further adjusted the company's application by half, directing that cost should follow benefit and stating, "However, the Commission further finds that the nature of the objectives appear to benefit both ratepayers and shareholders and it would be improper for the ratepayers to bear the full cost of this benefit." In a subsequent Black Hills case, NG-0061, the Commission again ordered a "known and measurable" adjustment. In NG-0060 the Commission disallowed the entire amount requested by SourceGas for cash incentive bonuses citing insufficient information on the record to adequately describe the bonuses.

Nebraska 2015: (Public Service Commission, Angela Melton, Director and Legal Counsel, Natural Gas Department, NPSC, 402-471-3101) There has been no change in the treatment of incentive compensation as a ratemaking issue in Nebraska.

Nebraska 2018: (Public Service Commission, Nichole Mulcahy, Director and Legal Counsel, Natural Gas Department, 402-471-0234) There have been no changes in Nebraska's handling of incentives. The Commission still practices the policy that cost should follow benefit and allows in rates the actual amount paid on incentive plans that benefit ratepayers. This treatment is the same for all incentive plans. There are no recent orders on point and no changes are anticipated.⁶

Nevada: 100% of long-term incentives are disallowed. Short-term incentives are divided between financial and operational goals with 100% of financially based plans disallowed. In Nevada Power's 2008 rate case, the Commission excluded 100% of the long-term plan for executives and key employees of the company, based on the fact that these costs mainly benefit shareholders. In Nevada Power's 2011 rate case, Docket No. 11-06006, the Company voluntarily excluded the costs of its long-term plan.

Nevada 2015: No change in Nevada's treatment.

Nevada 2018: (Nevada response provided by Mark Garrett) No change in Nevada's treatment.

New Mexico: (Public Regulation Commission, Charles Gunter, Accounting Bureau, 505-827-6940) The technical staff takes the general position that the portion of an incentive program that is based on increasing share value should be paid for by shareholders. Any that benefits ratepayers and makes up part of a reasonable base pay should be part of rates. Plans are evaluated on a case by case basis. Charles Gunter writes, "Staff took the position that 20 percent of Public Service Company of New Mexico's Results Based Pay costs were properly allocable to customers, because 20 percent of the maximum possible RBP award was tied to achieving goals pertaining to customer satisfaction, cost control, safety, reliability and operations efficiency. By comparison, 80 percent of the maximum possible award was tied to achieving corporate financial goals and EPS targets. See pages 11-13 of Andria Delling's (505-827-6962) testimony in 06-00210-UT."

New Mexico 2009: (Public Regulation Commission, Charles Gunter, Accounting Bureau Chief, Economist, 505-827-6975) The Commission does not favor incentive compensation plans that are tied to financial goals and tends to allow in rates those based on operational goals. This standard is applied to plans at all levels of utility employees and tends to knock out a greater proportion of executive plans. See Docket 07-00077-UT

New Mexico 2011: (Public Regulation Commission, Charles Gunter, Accounting Bureau Chief, Economist, 505-827-6977) There has been no change in NMPRC's treatment of incentive compensation except that due to the current economic conditions, Staff is even more opposed to incentive compensation and wage increases.

⁶ In a 2007 rate case, NG-0041, the Commission disallowed 50%, directing that cost should follow benefit and stating, "However, the Commission further finds that the nature of the objectives appear to benefit both ratepayers and shareholders and it would be improper for the ratepayers to bear the full cost of this benefit."

New Mexico 2015: (Public Regulation Commission, Charles Gunter, Accounting Bureau Chief, Economist, 505-827-6977) Incentive programs tied to measures that benefit ratepayers (such as operation and safety) are allowed in rates. Programs tied to the financial performance of the utility (e.g. stock price or ROE) are not allowed in rates. Executive incentive plans receive more scrutiny as they are more likely to have financial measures. They can also be challenged if the overall percentage is out of line. One major utility in New Mexico no longer includes the compensation of its top 5 executives in rate applications. The treatment of incentive compensation as a ratemaking issue has become generally established by practice and plans are considered on a case by case basis. There are no recent orders setting out this treatment, and no changes are anticipated.

New Mexico 2018: (Public Regulation Commission, Charles Gunter, Accounting Bureau Chief, Economist, 505-827-6977)) There has been no major change in the treatment of incentive compensation since the last update. The Commission considers this issue on a case by case basis and generally allows recovery through rates of those incentives that are reasonable in amount and tied to metrics that have benefit for customers, such as operational excellence and safety. Incentives that are financially based, for example those tied to stock price performance or earnings, are not allowed in rates. This treatment was followed in the Southwest Public Service Company's 2017 rate case, 17-00255-UT. The Commission described this treatment as its longstanding practice in the order in Public Service Company of New Mexico's rate case, 15-00261-UT. Some utilities in New Mexico no longer seek recovery of management incentives in rates.

North Dakota: (PSC, Mike Diller, Director of Accounting, 701-328-4079) In North Dakota, the general policy is the portion that relates to earnings of the shareholders is disallowed and the rest is included.

North Dakota 2009: (PSC, Mike Diller, Director of Accounting, 701-328-4079) Historically, North Dakota has followed the general policy that the portion of incentive compensation that relates to shareholder earnings is disallowed and the rest is included. The issue has recently been reframed. In the last rate case (Xcel/Northern States Power Company) the Commission followed the "Minnesota Solution": they capped incentive compensation for employees at 15% of base pay (company had asked for 25%). Any incentive compensation over the 15% level was not included in rates. Executive incentive compensation was not allowed in rates, and was not sought by the company to be in rates in this case nor in the last Xcel case (see p. 2, of McDaniel, Direct – attached; and p. 46, C of A.E. Heuer).

North Dakota 2011: (PSC, Mike Diller, Director of Accounting, 701-328-4079) The Commission has not accepted the financial verses performance, or shareholder verses ratepayer perspective on incentive compensation as recently argued by witness George Mathai. The Commission chose to look at the overall compensation and judge whether or not it was reasonable compared to the market. Other than Xcel, the utilities in North Dakota (Otter Tail and MDU) are highly diversified now (with mostly unregulated operations, e.g. MDU 90%). This allows utility executives to draw on the unregulated components for their compensation.

North Dakota 2015: (PSC, Mike Diller, Director of Accounting, 701-328-4079) Incentive compensation is dealt with on a case by case basis and there is no standard policy for the issue. The Commission has in the past limited incentives to 15% of salary. The general approach is to determine if

incentive compensation is reasonable and fair based on market analysis. There have been no recent orders on point, and no changes in treatment are anticipated.

North Dakota 2018: (PSC, Patrick Fahn, Director of Public Utilities Division, 701-328-4079) Incentives are treated on a case by case basis, but the Commission's general policy is to allow in rates incentive compensation that is tied to customer benefit and to disallow incentives tied to company financials and corporate benefit. This treatment is the same for all types of incentive plans. Executive incentives are always requested by the utilities but are historically not allowed in rates unless shown that the incentive compensation is tied to customer benefits. The current 2017 Otter Tail rate case, PU-17-398, is expected to follow this treatment. No changes to this treatment are anticipated in the near future.

Oklahoma : The Commission excludes incentive payments tied to financial performance. From a practical perspective this means that all executive stock plans are excluded and some portion of the annual cash plan for all employees. Since the Commission has not been able to determine in recent years the precise portion of the annual plans tied to financial measures, the Commission has excluded 50% of the expense. All of the executive stock plan costs are routinely excluded. (See Commission orders in AEP-PSO Cause No. PUD 06-285; OG&E Cause No. PUD 05-151; and ONG Cause No. PUD 04-610).

Oklahoma 2009: The Commission's policy toward incentive compensation is unchanged in 2009. In AEP-PSO's recently decided rate case (final order issued 1-14-09), the Commission exclude all of the long-term incentive compensation plans and 50% of the annual plans. (See Final Order No. 464437 in AEP-PSO Cause No. 08-144).

Oklahoma 2011: The Commission's policy toward incentive compensation is unchanged in 2011.

Oklahoma 2015: No change in Oklahoma's treatment.

Oklahoma 2018: (Oklahoma response provided by Mark Garrett) No change in Oklahoma's treatment.

Oregon: (PUC, Judy Johnson, Mgr. Rates and Tariffs, 503-378-6636) Oregon PUC's general policy is that all officer bonuses are 100% deleted from rates. For employee incentives plans, the part that is based on customer service is allowed and the part that is based on increased return is disallowed, resulting in 50-50 to 70-30 splits between shareholders and ratepayers. Utilities have begun to adopt this structure in their IC plans.

Oregon 2009: (PUC, Judy Johnson, Mgr. Rates and Tariffs, 503-378-6636) No substantial change in treatment. The Commission's general policy is to evaluate plans based on whether they benefit the customers or the company. Customer-based plans (involving reliability, response speed, etc) are called "merit" plans. Company-based plans (which track increases to the bottom line, ROE, etc) are called "performance" plans. 50% of the cost of merit plans is disallowed from rates and 75% of performance plans are disallowed from rates. 100% of officer bonuses are disallowed. A recent order reflecting this policy is found in Docket UE 197, Order No. 09-020 (attached).

Oregon 2011: (PUC, Judy Johnson, Mgr. Rates and Tariffs, 503-378-6636) No change in treatment. Still categorize "merit" or "performance" plans and disallow from rates 50% and 75% respectively. 100% of officer bonuses are disallowed.

Oregon 2015: (PUC, Judy Johnson, Mgr. Rates and Tariffs, 503-378-6636) The Commission's general policy is based on the idea that customers should not have to pay for incentive compensation based on financial goals such as rate of return. This treatment typically results in 50% to 75% of short-term incentives being allowed in rates. However, in the case of a plan with 3 of its 4 goals based on financial measures, 75% of the cost of that plan would be excluded from rates. The only long-term plans are for officers, and 100% of officer incentives are excluded from rates. This treatment is not expected to change.

Oregon 2018: (PUC, John Crider, Administrator - Energy Rates, Finance and Audits Division, 503-373-1536) The treatment of incentives in Oregon has not changed. Short-term, non-officer incentive plans are seen as having benefit to ratepayers; 50% of merit-based plans are disallowed from rates and 75% of plans related to company performance are disallowed⁷. Long-term officer and executive plans are seen as benefitting shareholders and are 100% disallowed⁸. This is a long-standing policy based on previous orders.

South Dakota: (PUC, Dave Jacobson, Analyst, 605-773-3201) The criteria used here is incentives that are triggered by shareholder returns are disallowed.

South Dakota 2009: (PUC, Dave Jacobson, Analyst, 605-773-3201) The Commission's general policy is to disallow the portion of incentive plans that are based strictly on returns. Current treatment also includes disallowing both executive and non-executive management incentive compensation. Also, there are no incentive compensation plans for union employees. Rate cases settle here so there are no orders on point.

South Dakota 2011: (PUC, Dave Jacobson, Analyst, 605-773-3201) South Dakota PUC is opposed to including in rates incentive compensation plans based on the company's financial performance. In Docket No. EL 08-030 the settlement excluded bonuses related to "stockholder-benefitting financial goals." The settlement in Xcel rate case Docket No. EL09-009 removed payments based on financial performance indicators. In the settlement agreement signed July 7, 2010 in the Black Hills Power rate case Docket No. EL09-018 the Staff Memorandum states, "The settlement removes financial based incentive payments that were included in the capitalized labor costs for plant. Shareholders are the overwhelming beneficiaries of incentive plans that promote the financial performance of the Company and therefore should be responsible for the cost of such compensation." Jacobson noted that several utilities have whole incentive programs that hinge on whether or not the company earns a certain return. These financial prerequisites cause the whole plans to be excluded from rates. The same treatment is used for management and employee plans.

⁷ See Orders: 76-601 p.13, 77-125 p. 10, 87-406 pp. 42-43

⁸ See Orders: 99-033 p. 62 and 97-171 pp.74-76

South Dakota 2015: (PUC, Eric Paulson, Utility Analyst, 605-773-6347) South Dakota considers incentive compensation on a case by case basis. Their general policy is to evaluate each plan and disallow the portion based on financial performance indicators. This treatment is set forth in the recent case EL14-026 in which the order specifically excluded the amount "tied to the Company's financial results." This policy is not anticipated to change.

South Dakota 2018: (PUC, Eric Paulson, Utility Analyst, 605-773-6347) There has been no change in South Dakota's treatment of incentives since 2015. Incentives with stockholder-benefiting financial goals are excluded from rates. This treatment is the same for incentive plans at all levels. Recent orders (issued 6/15/16) which follow this treatment are found in dockets EL 15-024 and NG 15-005. This treatment is not expected to change.

Texas: The Public Utility Commission regulates the electric utilities in Texas. The PUC's general rule is that incentive payments designed to increase the financial position of the utility are excluded. For example, in PUC Docket No. 28840, the Commission disallowed sixty-six percent (66%) of AEP-Texas Central's test year incentive payments in the amount of \$4.2 million. This was the portion of the utility's incentive payments that was based on financial performance measures. (See Application of AEP Texas Central Company for Authority to Change Rates, Docket No. 28840; SOAH Docket No. 473-04-1033, Final Order, August 15, 2005; ALJ's Proposal for Decision at page 113 in PUC Docket No. 28840, SOAH Docket No. 473-04-1033, issued July 1, 2004. The PFD with respect to the treatment of incentive compensation was adopted by the Commission in its Final Order.)

Gas utilities are regulated by the Railroad Commission. The treatment of the RRC is consistent; financial incentives are out of rates and customer-related incentives are allowed in. Examples of this treatment can be found in Atmos 9670 Order and Order on Rehearing, Texas Gas Service Company 9988 Final Order, Centerpoint 9902 Final Order and Centerpoint 10106 Final Order. In Docket 9670 both the executive and employee plans for Atmos Mid-Tex were found not to be just and reasonable because they, "advanced the interest of shareholders, and [are] driven by Company earnings." None of the costs of these programs were allowed in rates. In Docket 9988 the RRC found 100% of long-term and 90% of short-term incentives expense was "unreasonable" because it was related to the financial performance of ONEOK Inc. 10% of the short-term plan was allowed in rates because it was based on safety metrics.

Texas 2015: (PUC, Larry Reed, Senior Fuel Analyst, 512-936-7357) No response from Texas PUC at this time. A recent example of the Texas commission's well established policy of excluding financially based incentives is set forth in 2011 rate case of Entergy Texas Inc. (PUC Docket No. 39896). In PUC Docket No. 40295, Entergy's application for rate case expense in the 39896 case, the Commission also disallowed the amount of rate-case expenses related to financially-based incentive compensation. The 40295 Order reads at page 2:

The Commission affirms the proposal for decision regarding the need to reduce Entergy's recoverable expenses due to an unreasonable position pursued by Entergy in the rate case and also affirms the use of the "issue-specific reduction approach" to determine how to calculate an appropriate reduction in rate-case expenses when the utility takes positions that are in conflict with Commission precedent.

Specifically, the Commission agrees with the ALJ that reductions should be made to Entergy's recoverable rate-case expenses for Entergy

attempting to recover financially-based incentive compensation in base rates. The Commission has repeatedly ruled that a utility cannot recover the cost of financially-based incentive compensation because financial measures are of more immediate benefit to shareholders and financial measures are not necessary or reasonable to provide utility services.⁹ The Commission concludes that it should follow its well-established policy here.

However, the ALJ did not include all of the impacts attendant to the disallowance for incentive compensation.¹⁰ To calculate the amount of the reduction in rate-case expenses related to financially-based incentive compensation, the Commission starts with Entergy's initial rate-case expense request, reduced by \$208,494 in disallowances made by the ALJ and affirmed by the Commission. The Commission further reduces this amount by an additional \$522,244.66, which is the amount of rate-case expenses related to financially-based incentive compensation using the issue-specific reduction approach.

Texas 2015: (Railroad Commission, Mark Evarts, Director, Market Oversight and Safety Services Division, 512-427-9057) No response from Texas RRC at this time.

Texas 2018: (PUC, Anna Givens, Director, Financial Review, 512-936-7462) The longstanding policy of the Commission is to exclude from rates all financially-based incentives. Incentives based on operational goals may be included in rates. Long-term incentives are typically financially based and are excluded. Executive incentives receive the same treatment. This treatment is not proscribed by statute or rule, but has been the consistent policy of the Commission since 2005 when it issued the Final Order in Docket No. 28840. Recent orders in litigated cases that set forth this treatment include SWEPCO rate cases Docket Nos. 40443 and 46449, and the SPS rate case Docket No. 43695. One recent refinement to the treatment of this issue in Texas is that for plans that are otherwise based on acceptable operational metrics but are paid only if a financial goal is met, only 50% of the portion that is subject to the financially-based proviso is allowed in rates. This split occurs before consideration of the individual components of the compensation plan goals and 100% of incentive plan goals tied directly to financial goals are further excluded. In the SWEPCO proceeding, Docket No. 46449, the Company's EPS funding goal was weighted 75%, so the disallowance was 50% of the 75% weighting and resulted in an adjustment that was less than 50% of the total plan that was otherwise based upon acceptable operational metrics. This refinement reflects that a plan has a financially-based funding trigger and requires employees to meet metrics that include financial goals, in addition to performance-

⁹ *Application of AEP Texas Central Company for Authority to Change Rates*, Docket No. 28840, Proposal for Decision at 92-97, Findings of Fact Nos. 164-170, Order at 35 (Aug. 15, 2005); *Application of AEP Texas Central Company for Authority to Change Rates*, Docket No. 33309, Proposal for Decision at 116-121, Finding of Fact No. 82, Order on Rehearing at 12 (March 4, 2008); *Application of Oncor Electric Delivery Company, LLC, for Authority to Change Rates*, Docket No. 35717, Proposal for Decision at 96-100, Finding of Fact No. 93, Order on Rehearing at 22 (Nov. 30, 2009); and *Application of CenterPoint Electric Delivery Company, LLC, for Authority to Change Rates*, Docket No. 38339, Proposal for Decision at 66-67, Findings of Fact Nos. 81-83, Order on Rehearing at 22 (June 23, 2011).

¹⁰ Docket No. 39896, Order on Rehearing at 5-6, 7-8 (Nov. 2, 2012).

related goals. There are no imminent changes in the PUC's treatment, however there are some efforts to have it codified as a Commission Rule.

Texas 2018: (Railroad Commission, Mark Brock, Utility Analyst, 512-463-7018) The Commission handles incentive compensation on a case by case basis.

(Texas Railroad Commission Update) A statute (H.B. 1767) passed in 2019 for gas utilities, but not electric utilities, establishes a rebuttable presumption that short-term incentives for utility employees are reasonable and necessary if the utility can show they are market-based. The statute does not include financial-based incentives for named executives. Also, it is not clear if the statute covers incentives allocated from corporate or from a service company.

Utah: (PSC, Jim Logan, Commission Utility Economist (PSC), 801-530-6716) The general policy in Utah is the portion of the plan based on rate payer benefit, such as service quality, is allowed and the portion that relates to earning and rate of return are disallowed. See US West Communications Rate Case Docket 95-049-05; Missouri Corp. Rate Case Docket 97-035-01 Order signed 3/4/99, pp. 10-12.

Utah 2009: (PSC, Jim Logan PhD, Commission Utility Economist (PSC), 801-530-6707) The Commission's general policy (backed by orders) is to allow in rates the parts of a plan that are tied to ratepayer benefit and disallow the parts tied to financial goals. Executive incentive compensation is excluded from rates. The recent final order in 07-035-93 follows this general policy. See also US West Communications Rate Case Docket 95-049-05; Missouri Corp. Rate Case Docket 97-035-01 Order signed 3/4/99, pp. 10-12.

Utah 2011: (PSC, Carol Revelt, Energy and Electric Economist, 801-530-6711) There have been no changes in Utah's treatment of incentive compensation. The Commission's general policy is to allow in rates the parts of a plan that are tied to ratepayer benefit and disallow the parts tied to financial goals.

Utah 2015: (PSC, Carol Revelt, Energy and Electric Economist, 801-530-6711) The Commission's general policy is to allow in rates the parts of a plan that are tied to ratepayer benefit and disallow the parts tied to financial goals. This policy was followed in the PacifiCorp General Rate Case Docket No. 07-035-93, pp. 61-62; the US West Communications Rate Case Docket 95-049-05; and Missouri Corp. Rate Case Docket 97-035-01, pp. 10-12. There are no recent orders on point and no changes in policy are anticipated.

Utah 2018: (PSC, Carol Revelt, Energy and Electric Economist, 801-530-6711) The Commission considers incentive compensation on a case by case basis and whether the incentive compensation program is reasonable. Historically the general policy has been to allow in rates the parts of a plan that are tied to ratepayer benefit and disallow the parts tied to financial goals. There have been no recent commission decisions addressing this issue.

Washington: (WUTC, Roland Martin, staff, 360-664-1304) Treated on a case by case basis. Typically allow the component tied to efficiency increases and disallow the part that results from increasing the bottom line. See Docket 061546, Pacific Power and Light, Order

Washington 2009: (WUTC, Roland Martin, staff, 360-664-1304) No change in treatment. Evaluated on a case by case basis, this treatment allows the parts of plans tied to measures such as reliability and customer satisfaction and disallows the parts tied to financial measures and the bottom line.

Washington 2011: (WUTC, Roland Martin, Regulatory Analyst, 360-664-1304) No change in treatment. Still addressed on case by case basis, allowing in rates those incentives that are tied to operational efficiency or other measures which benefit ratepayers, and disallowing incentives based on return on earnings or other measures that benefit the shareholders. Recommended website: www.utc.wa.gov.

Washington 2015: (WUTC, Roland Martin, Regulatory Analyst, 360-664-1304) No change in treatment. Still addressed on case by case basis, allowing in rates those incentives that are tied to operational efficiency or other measures which benefit ratepayers, and disallowing incentives based on return on earnings or other measures that benefit the shareholders.

Washington 2018: (WUTC, Amy Andrews, Senior Policy Advisor, 360-664-1304) Washington's treatment of incentive compensation is largely based on previous cases, but remains a case-by-case basis. Generally, Short-term incentives are allowed in rates with Long-term incentives being excluded. There are no recent orders that set forth this treatment.

Wyoming: (PSC, Marci Norby, Senior Rate Analyst, 307-777-5720) Wyoming considers incentive compensation on a case by case basis. The general approach is to determine if the program is reasonable.

Wyoming 2009: (PSC, Marci Norby, Senior Rate Analyst, 307-777-5720) Executive incentive compensation plans are all excluded from rates. Employee incentive compensation plan are evaluated on a case by case basis. Criteria for evaluation include that optional portions of the plans are based on performance goals not financial measures, and the total compensation is compared to a market standard. Currently most employee plans meet these criteria and are allowed in rates.

Wyoming 2011: (PSC, Marci Norby, Senior Rate Analyst, 307-777-5720) Policy here remains the same, distinguishing between employee programs that benefit the ratepayer or the stockholders and requiring the benefitting party to pay. Executive plans are excluded.

Wyoming 2015: (PSC, Marci Norby, Senior Rate Analyst, 307-777-5720) Incentive compensation has not been an issue in some time here. There are no governing regulations, statutes or general policies and the issue would be decided on a case by case basis after considering the history and goals of a program in the context of a rate case. There are no recent orders on point, and no changes in treatment are anticipated.

Wyoming 2018: (PSC, Marci Norby, Senior Rate Analyst, 307-777-5720) There has been no change in the way that incentives are treated in Wyoming. Incentives are generally evaluated on a case by case basis to determine if they are just and reasonable, giving attention to plan goals

and historical context. There are no governing regulations, statutes or general policies in place, and there are no recent orders on point. No changes in treatment are anticipated.

**SOAH DOCKET NO. 473-21-0538
PUC DOCKET NO. 51415**

**APPLICATION OF SOUTHWESTERN § BEFORE THE STATE OFFICE
ELECTRIC POWER COMPANY FOR § OF
AUTHORITY TO CHANGE RATES § ADMINISTRATIVE HEARINGS**

DIRECT TESTIMONY AND EXHIBITS

OF MARK E. GARRETT

EXHIBIT MG-4:

RFI RESPONSES REFERENCED IN TESTIMONY

EXHIBIT MG-4
RFI RESPONSES REFERENCED IN TESTIMONY

American Electric Power

2019 Annual Incentive Compensation Plan

Template

Introduction

The objectives of AEP's Annual Incentive Compensation Plan (the Plan) are to:

- Attract, retain, engage and motivate employees to further the objectives of the company, its customers and the communities it serves;
- Enable high performance by communicating and aligning employee efforts with the Plan's performance objectives; and
- Foster the creation of sustainable shareholder value through achievement of AEP's goals.

2019 Overview

For 2019 the Executive Council, each Operating Company, Distribution Services, Regulated Generation, Competitive Generation, Transmission, Nuclear Generation, and Energy Supply (non-generation), have an annual incentive compensation plan (ICP) with separate goals.

All other groups participate in the ICP program based on the weighted average score¹ of the above groups and do not have separate incentive goals.

The Plan provides annual incentive compensation to motivate and reward employees based on AEP's performance, business unit performance (if applicable) and, for employees whose payout is discretionary, their individual performance. Annual incentive funding for all plans is tied to AEP's Operating Earnings per Share (70% weight), safety and compliance (10% weight) and strategic initiatives (20% weight).

Linking annual incentive compensation to AEP's earnings aligns it with the value employees have created and ensures that AEP meets its commitments to all other stakeholders before setting aside dollars for annual incentive awards. Relative individual performance is reflected in managers' discretionary allocations from their award pool for all employees in positions in the 20-grade salary plan (SP20). Group or team performance may also be reflected through discretionary adjustments in the allocation of funding from the annual incentive pool at higher organizational levels.

The Plan is intended to drive the achievement of objectives by clearly communicating them, conveying their importance, aligning employee efforts toward their achievement and further motivating employees to achieve them.

Performance measures are selected, whenever practical, to provide a "line of sight" that enables employees to see how the work they perform affects their annual incentive award. Objective and quantifiable performance measures are used when they are available but the Plan may also include subjective assessments of performance in less quantifiable areas as well as subjective individual performance assessments.

Safety remains the first priority irrespective of other ICP goals and other objectives the Company

¹ The scores are weighted by the sum of the target awards for all participants in each group.

establishes. To help ensure that all employees have a personal stake in maintaining safe work practices, a substantial portion of all AEP ICP plans is tied to both AEP employees and contract workers safety.

Operating Performance Measures and Weights

Specific performance measures vary by business unit and operating company. The score for each performance measure may range from 0% to 200% of target.

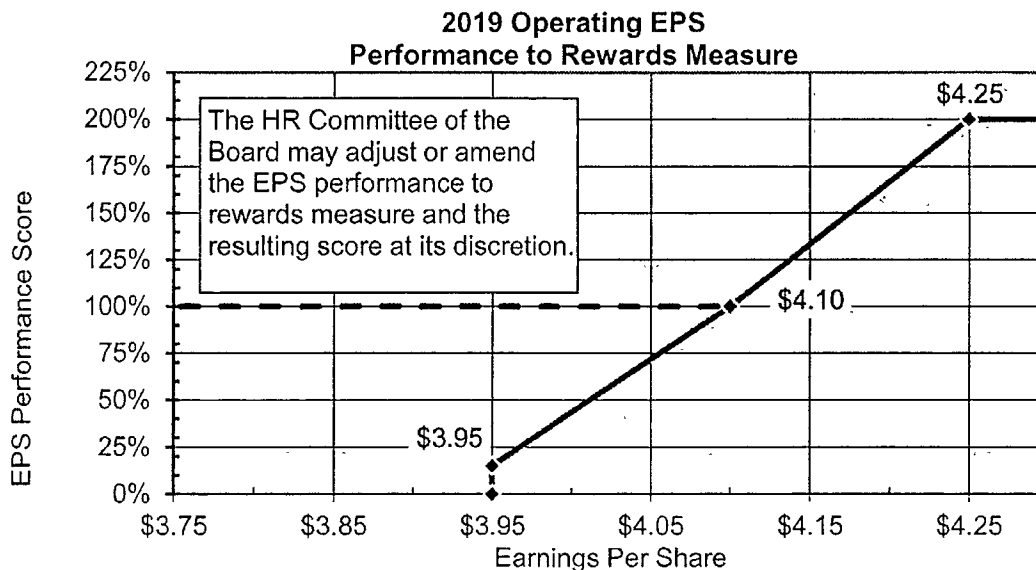
2019 Funding Measures

The 2019 funding measures were established by the HR Committee of the Board early in 2019. The maximum funding available is 200% of target funding. As in past years, the CEO and HR Committee of the Board have discretion to adjust annual incentive funding. All incentive plan funding is contingent on AEP achieving operating earnings of at least \$3.95 per share for 2019.

Operating Earnings Per Share (70% Weight)

AEP is committed to generating sustainable value for all its stakeholders through its earnings and growth. Therefore 70% of annual incentive funding is tied to AEP's Operating Earnings per Share. This ensures that funding is commensurate with the Company's operating earnings and the extent to which the company can afford to pay annual incentive compensation while also serving the interests of its shareholders, customers and other stakeholders. It also:

- Aligns employee interests with those of customers by strongly encouraging expense discipline,
- Ensures that adequate earnings are generated for AEP's shareholders and continued investment in AEP's business before setting aside annual incentive compensation for employees, and
- Further aligns the financial interests of all AEP employees with the results employees deliver to the Company and all its stakeholders.



American Electric Power

2020 Annual Incentive Compensation Plan

For [B.U. / Operating Company Name]

Introduction

The objectives of the American Electric Power 2020 Annual Incentive Compensation Plan For [Business Unit or Operating Company Name] (the "Plan") are to:

- Attract, retain, engage and motivate employees to operate the business of the company efficiently and effectively for the benefit of customers, shareholders, employees and the communities we serve;
- Encourage the continued development of a high performance company culture; and
- Communicate and align the efforts of each team and employee with the Plan's objectives to increase the focus on these objectives, foster performance improvement and create of sustainable value.

2020 Overview

The purpose of the Plan is to foster the development of a higher performance culture, which, along with the Plan's performance measures, better enables the achievement of annual performance objectives and continuous improvement.

For 2020 there are separate annual incentive compensation plans ("ICP") and goals for the Executive Council, each AEP Operating Company, T&D Performance Management, Regulated Generation, Competitive Generation, Transmission, Nuclear Generation, Energy Supply (non-generation) and Energy Supply (generation). All other groups participate in the ICP program based on the weighted average score¹ of the above groups and do not have separate incentive goals. As in the past, the goals for the Executive Council are the funding goals for all ICPs, which aligns goals and scores across AEP.

Awards are determined based on AEP's performance and, if applicable, business unit or operating company performance and individual employee performance. For 2020, we changed the way we measure AEP performance to a single goal: **AEP operating earnings per share (Operating EPS) with a 100% weight**. This change simplifies ICP funding for 2020 by focusing it on a single, critical financial objective that will better ensure that we all remain focused on taking the necessary actions to protect and maintain the financial health of the Company, which is in the interests of all stakeholders, including employees. Linking annual incentive compensation to AEP's earnings aligns it with the value employees create each year and ensures that AEP meets its commitments to other stakeholders before setting aside ICP award funding for employees.

AEP's Safety, Compliance and Strategic Initiatives for 2020 will be maintained and assessed for a potential discretionary adjustment to the AEP Performance score but these goals will not directly contribute to ICP scores. These objectives remain critical to our successes and operations this year and beyond. Without a continued progress on safety, compliance and other strategic objectives, reaching our Operating EPS goal for the year would be a hollow achievement. We will continue to pursue these objectives and report on our performance against them. Our Safety, Compliance and

¹ Weighted by the sum of the target awards for all participants in each group with separate incentive goals.

Strategic Initiatives may be considered by the Human Resources Committee of AEP's Board of Directors (HR Committee) for a potential (but not required) discretionary adjustment to ICP funding, which could be either positive or negative. Please see Appendix 1 for details of these initiatives.

PERFORMANCE MEASURES

Performance measures are selected to focus employee's efforts on the company's goals and objectives that provide, when possible, a 'line of sight' that enables employees to see how their work and performance contributes to the company's performance and to their annual ICP award. Goals that provide such a 'line of sight' foster high employee engagement and, which leads to improved employee and company performance. Tying the company's goals and objectives to incentive compensation more clearly conveys their importance, aligns team and employee efforts with their achievement, engages employees in their achievement and provides an incentive and shared fate that motivates employees to achieve these goals and objectives.

OPERATING MEASURES

The 2020 operating performance measures and weights vary by business unit and operating company. Please see Appendix 2 for the operating performance measures and weights for the Plan.

FUNDING MEASURE

The HR Committee established the 2020 threshold, target and maximum levels for the AEP Operating Earnings goal early in 2020. The Threshold and target levels coincide with AEP's public earnings guidance. The score may range from 0% to 200% of target, which limits the maximum funding to 200% of target funding. As in past years, the CEO and HR Committee have the discretion to adjust annual incentive funding and have indicated that they would consider AEP's performance towards the Safety, Compliance and Strategic Initiatives in making any discretionary adjustment. All incentive plan funding is contingent on AEP achieving Operating EPS of at least \$4.25 for 2020.

Operating Earnings Per Share (100% Weight)

AEP is committed to generating sustainable value for all its stakeholders through its earnings and growth. Therefore 100% of annual incentive funding is tied to AEP's Operating EPS. This ensures that funding is commensurate with the Company's operating earnings and the extent to which the company can afford to pay annual incentive compensation while also serving the interests of its shareholders, customers and other stakeholders. It also:

- Aligns employee interests with those of customers by strongly encouraging expense discipline,
- Ensures that adequate earnings are generated for AEP's shareholders and continued investment in AEP's business before setting aside annual incentive compensation for employees, and
- Further aligns the financial interests of all AEP employees with the results employees deliver to the Company and all its stakeholders.

In the event that AEP's Operating EPS is less than the \$4.25 threshold for 2020 then no incentive awards will be paid under the Plan. Operating EPS must reach threshold for any payout to occur..

**SOAH DOCKET NO. 473-21-0538
PUC DOCKET NO. 51415**

**SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO CITIES
ADVOCATING REASONABLE DEREGULATION'S FOURTH SET OF REQUESTS
FOR INFORMATION**

Question No. CARD 4-5:

Payroll related expenses: Please provide the following information for each pay period in the test year for each employee group with a separate payroll annualization calculation in the Company's work papers to the extent that information is available, preferably in an Excel-compatible file with fully functional formulas:

- a. number of employees
- b. regular pay
- c. overtime pay
- d. compensated absences not included in b. above
- e. incentives or bonuses
- f. regular hours
- g. overtime hours

Response No. CARD 4-5:

See CARD_4-5_Attachment_1.xlsx for the payroll related information requested for each pay period in the test year.

CARD 4-5 Attachment 1 is available electronically on the PUC Interchange.

Prepared By: Frances K. Bourland

Title: Regulatory Acctg Case Mgr

Sponsored By: Michael A. Baird

Title: Mng Dir Acctng Policy & Rsrch

SOUTHWESTERN ELECTRIC POWER COMPANY
PAYROLL INFORMATION BY PAY PERIOD
FOR THE TEST YEAR ENDED 3/31/2020

SOAH Docket No. 473-21-0538

PUC Docket No. 51415

CARD's 4th, Q. # CARD 4-5

Attachment 1

Page 1 of 1

Pay Period Start	Pay Period End	# employees	Base \$	OT \$	Incentives	Regular hours	OT hours
3/23/2019	4/5/2019	1,468	4,890,366	680,018		115,591	11,329
4/6/2019	4/19/2019	1,466	4,466,163	1,098,094		115,581	19,127
4/20/2019	5/3/2019	1,464	4,713,760	918,223		114,818	14,541
5/4/2019	5/17/2019	1,465	4,442,799	1,853,481		110,653	33,297
	5/31/2019				212,576		
5/18/2019	5/31/2019	1,466	4,450,737	851,665		115,777	14,607
6/1/2019	6/14/2019	1,460	4,861,941	662,982		113,837	11,093
6/15/2019	6/28/2019	1,458	4,834,328	1,498,894		109,515	27,078
6/29/2019	7/12/2019	1,457	4,305,578	635,793		114,891	10,073
7/13/2019	7/26/2019	1,458	4,547,350	572,081		119,503	9,174
	7/31/2019				4,217,300		
7/27/2019	8/9/2019	1,458	4,728,653	461,562		115,439	8,458
8/10/2019	8/23/2019	1,463	4,766,116	571,524		115,286	9,079
8/24/2019	9/6/2019	1,456	4,413,689	1,133,270		111,872	18,499
9/7/2019	9/20/2019	1,459	4,947,345	611,285		115,309	9,543
9/21/2019	10/4/2019	1,458	4,767,165	701,149		115,218	11,524
10/5/2019	10/18/2019	1,460	4,692,385	821,989		115,225	13,552
	10/31/2019				47,386		
10/19/2019	11/1/2019	1,459	4,698,138	1,339,597		111,800	21,736
11/2/2019	11/15/2019	1,462	4,705,899	730,630		115,519	12,260
11/16/2019	11/29/2019	1,463	4,222,627	567,792		115,735	9,837
11/30/2019	12/13/2019	1,460	5,483,773	511,510		115,343	8,169
12/14/2019	12/27/2019	1,463	3,736,159	415,793		114,975	6,934
12/28/2019	1/10/2020	1,467	4,806,170	354,597		115,451	5,768
1/11/2020	1/24/2020	1,459	5,684,168	839,737		114,649	14,308
1/25/2020	2/7/2020	1,467	4,801,469	398,751		115,901	6,575
2/8/2020	2/21/2020	1,468	4,709,963	417,410		115,971	6,892
	2/29/2020				1,715,974		
	3/6/2020				18,087,787		
2/22/2020	3/6/2020	1,464	4,838,683	469,911		115,775	7,872
3/7/2020	3/20/2020	1,459	4,657,639	422,971		115,602	7,005
	3/31/2020				11,624		

**SOAH DOCKET NO. 473-21-0538
PUC DOCKET NO. 51415**

**SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO CITIES
ADVOCATING REASONABLE DEREGULATION'S FIFTH SET OF REQUESTS FOR
INFORMATION**

Question No. CARD 5-5:

Payroll related expenses: Please update the response to CARD 4-6 through the latest available date.

Response No. CARD 5-5:

See CARD 5-5 Attachment 1 for the payroll related expenses provided in response to CARD 4-6 for the additional pay-periods through December 31, 2020.

Prepared By: Frances K. Bourland

Title: Regulatory Acctg Case Mgr

Sponsored By: Michael A. Baird

Title: Mng Dir Acctng Policy & Rsrch

SOUTHWESTERN ELECTRIC POWER COMPANY
PAYROLL INFORMATION BY PAY PERIOD
FOR PAY PERIODS IN THE MONTHS NOVEMBER AND DECEMBER 2020

Pay Period Start	Pay Period End	# employees	Base \$	OT \$	Incentives	Regular hours	OT hours
10/17/2020	10/30/2020	1,455	4,742,239	930,813		111,711	16,304
10/31/2020	11/13/2020	1,451	4,874,717	1,569,444		110,587	22,258
11/14/2020	11/27/2020	1,446	4,841,628	524,862		111,551	8,004
11/28/2020	12/11/2020	1,440	4,847,958	530,802		110,923	8,693
12/12/2020	12/25/2020	1,452	4,357,280	448,575		111,716	8,975

SOUTHWESTERN ELECTRIC POWER COMPANY
PAYROLL INFORMATION BY PAY PERIOD
FOR THE TEST YEAR ENDED 3/31/2020

Pay Period Start	Pay Period End	# employees	Base \$	OT \$	Incentives	Regular hours	OT hours
3/23/2019	4/5/2019	1,468	4,890,366	680,018		115,591	11,329
4/6/2019	4/19/2019	1,466	4,466,163	1,098,094		115,581	19,127
4/20/2019	5/3/2019	1,464	4,713,760	918,223		114,818	14,541
5/4/2019	5/17/2019	1,465	4,442,799	1,853,481		110,653	33,297
	5/31/2019				212,576		
5/18/2019	5/31/2019	1,466	4,450,737	851,665		115,777	14,607
6/1/2019	6/14/2019	1,460	4,861,941	662,982		113,837	11,093
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6/29/2019	7/12/2019	1,457	4,305,578	635,793		114,891	10,073
7/13/2019	7/26/2019	1,458	4,547,350	572,081		119,503	9,174
	7/31/2019				4,217,300		
7/27/2019	8/9/2019	1,458	4,728,653	461,562		115,439	8,458
8/10/2019	8/23/2019	1,463	4,766,116	571,524		115,286	9,079
8/24/2019	9/6/2019	1,456	4,413,689	1,133,270		111,872	18,499
9/7/2019	9/20/2019	1,459	4,947,345	611,285		115,309	9,543
9/21/2019	10/4/2019	1,458	4,767,165	701,149		115,218	11,524
10/5/2019	10/18/2019	1,460	4,692,385	821,989		115,225	13,552
	10/31/2019				47,386		
10/19/2019	11/1/2019	1,459	4,698,138	1,339,597		111,800	21,736
11/2/2019	11/15/2019	1,462	4,705,899	730,630		115,519	12,260
11/16/2019	11/29/2019	1,463	4,222,627	567,792		115,735	9,837
11/30/2019	12/13/2019	1,460	5,483,773	511,510		115,343	8,169
12/14/2019	12/27/2019	1,463	3,736,159	415,793		114,975	6,934
12/28/2019	1/10/2020	1,467	4,806,170	354,597		115,451	5,768
1/11/2020	1/24/2020	1,459	5,684,168	839,737		114,649	14,308
1/25/2020	2/7/2020	1,467	4,801,469	398,751		115,901	6,575
2/8/2020	2/21/2020	1,468	4,709,963	417,410		115,971	6,892
	2/29/2020				1,715,974		
	3/6/2020				18,087,787		
2/22/2020	3/6/2020	1,464	4,838,683	469,911		115,775	7,872
3/7/2020	3/20/2020	1,459	4,657,639	422,971		115,602	7,005
	3/31/2020				11,624		
	Totals	1,462	122,173,066				
3/21/2020	4/3/2020	1,457	4,958,465	468,773		115,486	7,724 From CARD_8-1_Attachment_1_(CARD_4-6_Attachment_1REVISED).xlsx
4/4/2020	4/17/2020	1,458	4,348,428	1,376,585		108,129	23,396 From CARD_8-1_Attachment_1_(CARD_4-6_Attachment_1REVISED).xlsx
4/18/2020	5/1/2020	1,455	4,662,077	1,318,582		111,693	22,542 From CARD_8-1_Attachment_1_(CARD_4-6_Attachment_1REVISED).xlsx
5/2/2020	5/15/2020	1,454	4,753,040	669,120		115,110	11,084 From CARD_8-1_Attachment_1_(CARD_4-6_Attachment_1REVISED).xlsx
5/16/2020	5/29/2020	1,454	4,552,200	731,604		115,150	11,254 From CARD_8-1_Attachment_1_(CARD_4-6_Attachment_1REVISED).xlsx
	5/31/2020				240,707		From CARD_8-1_Attachment_1_(CARD_4-6_Attachment_1REVISED).xlsx
5/30/2020	6/12/2020	1,458	5,041,366	501,193		115,201	8,377 From CARD_8-1_Attachment_1_(CARD_4-6_Attachment_1REVISED).xlsx
6/13/2020	6/26/2020	1,455	5,062,566	516,917		115,140	8,523 From CARD_8-1_Attachment_1_(CARD_4-6_Attachment_1REVISED).xlsx
6/27/2020	7/10/2020	1,457	4,390,502	646,722		115,311	10,227 From CARD_8-1_Attachment_1_(CARD_4-6_Attachment_1REVISED).xlsx
	7/17/2020				37,759		From CARD_8-1_Attachment_1_(CARD_4-6_Attachment_1REVISED).xlsx
7/11/2020	7/24/2020	1,457	4,259,093	425,750		115,066	8,207 From CARD_8-1_Attachment_1_(CARD_4-6_Attachment_1REVISED).xlsx
7/25/2020	8/7/2020	1,455	4,595,011	1,511,896		109,528	24,847 From CARD_8-1_Attachment_1_(CARD_4-6_Attachment_1REVISED).xlsx
8/8/2020	8/21/2020	1,455	4,809,396	1,057,833		112,374	16,305 From CARD_8-1_Attachment_1_(CARD_4-6_Attachment_1REVISED).xlsx
	8/31/2020				138,960		From CARD_8-1_Attachment_1_(CARD_4-6_Attachment_1REVISED).xlsx
8/22/2020	9/4/2020	1,455	4,654,448	2,749,362		103,703	47,886 From CARD_8-1_Attachment_1_(CARD_4-6_Attachment_1REVISED).xlsx
9/5/2020	9/18/2020	1,457	4,524,160	1,507,012		111,438	22,964 From CARD_8-1_Attachment_1_(CARD_4-6_Attachment_1REVISED).xlsx
9/19/2020	10/2/2020	1,455	4,892,715	904,665		114,122	13,688 From CARD_8-1_Attachment_1_(CARD_4-6_Attachment_1REVISED).xlsx
10/3/2020	10/16/2020	1,454	4,774,792	1,389,713		111,864	22,889 From CARD_8-1_Attachment_1_(CARD_4-6_Attachment_1REVISED).xlsx
	10/31/2020				35,431		From CARD_8-1_Attachment_1_(CARD_4-6_Attachment_1REVISED).xlsx
10/17/2020	10/30/2020	1,455	4,742,239	930,813		111,711	16,304 From CARD_5-5_Attachment_1.xlsx
10/31/2020	11/13/2020	1,451	4,874,717	1,569,444		110,587	22,258 From CARD_5-5_Attachment_1.xlsx
11/14/2020	11/27/2020	1,446	4,841,628	524,862		111,551	8,004 From CARD_5-5_Attachment_1.xlsx
11/28/2020	12/11/2020	1,440	4,847,958	530,802		110,923	8,693 From CARD_5-5_Attachment_1.xlsx
12/12/2020	12/25/2020	1,452	4,357,280	448,575		111,716	8,975 From CARD_5-5_Attachment_1.xlsx

Oct - Dec Annualized 123,233,995
Test Year Base Pay 122,173,066
Change From Test Year 100.87%

**SOAH DOCKET NO. 473-21-0538
PUC DOCKET NO. 51415**

**SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO COMMISSION
STAFF'S FIFTH REQUEST FOR INFORMATION**

Question No. Staff 5-24:

Has the Company experienced any reductions in force since the end of the test year? Does the Company anticipate any reductions in force between now and the end of the rate year? If the answer to either question is yes, please describe and quantify.

Response No. Staff 5-24:

Beginning June 8, 2020 through July 6, 2020, the company did offer a retirement incentive package to certain employees across the service company and SWEPCO. Only one SWEPCO employee accepted the retirement incentive package and a total of 189 employees reporting to AEPSC accepted the package.

Prepared By: Christopher N. Martel

Title: Regulatory Consultant Sr

Sponsored By: Lynn M. Ferry-Nelson

Title: Dir Regulatory Svcs

**SOAH DOCKET NO. 473-21-0538
PUC DOCKET NO. 51415**

**SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO
CITIES ADVOCATING REASONABLE DEREGULATION'S
SECOND SET OF REQUESTS FOR INFORMATION**

Question No. CARD 2-14:

Reference page 6, lines 8-13 of SWEPCO witness Seidel's direct testimony, please provide O&M expenses incurred for each of the three categories of distribution reliability programs for each of the last three calendar years and for the test year, for the total SWEPCO system and for the Texas retail jurisdiction.

Response No. CARD 2-14:

SWEPCO does not separately subdivide O&M expenses between the three major categories, with the exception of vegetation management.

Please see CARD 2-14 Attachment 1 for SWEPCO TX vegetation expenses, Total SWEPCO (TX, LA, and AR) vegetation expenses, and Total SWEPCO O&M expenses for the test year and the last three calendar years. SWEPCO TX Distribution O&M costs per year can be found in Figure 7 of Company Witness Seidel's direct testimony for the period requested.

Prepared By: Paul D. Flory
Sponsored By: Drew W. Seidel

Title: Regulatory Consultant Sr
Title: VP Dist Region Opers

	SWEPCO TX Veg Expenses	SWEPCO Veg Expenses (AR,LA,TX)	SWEPCO Distr O&M Expenses (AR,LA,TX)
Test Year	\$9,568,282	\$27,072,446	\$93,596,205
2019	\$9,359,676	\$26,619,472	\$90,316,730
2018	\$12,954,922	\$31,349,749	\$83,799,260
2017	\$6,025,129	\$22,001,521	\$85,912,772

CD ATTACHED

**TO VIEW PLEASE CONTACT
CENTRAL RECORDS
512-936-7180**